

Standing the test of time



Shiningbank Energy Income Fund

2003 Annual Report

TABLE OF CONTENTS

2	Rate of Return
3	Standing the Test of Time
4	A Top Performer
5	Fellow Unitholders
10	Corporate Governance
11	Directors and Management Team
12	Understanding Your Investment
13	Our Fundamentals
14	Quality Asset Base
16	The Gas Market
18	Acquisition 2003
19	Acquisition 2004
20	Reserves
22	Our costs to grow
23	Management's Discussion and Analysis
37	Financial Information
52	Five-Year Financial and Operating Review
54	Unitholders' Information
56	Corporate Information

This page: Shiningbank Lake. The Fund is named after Shiningbank Lake, located west of Edmonton, Alberta, which is close to one of the first properties acquired by the Fund. The name Shiningbank comes from the Aboriginal word for the lake describing its clay banks that shine like gold in the sun.

Consistent **top performer**

Shiningbank has consistently been a top performing investment in the oil and gas trust sector. Since inception in 1996, its experienced team of oil and gas professionals has acquired and managed high quality assets, primarily natural gas. Their active hands-on management includes marketing volumes to capture pricing highs, while bridging lows in commodity price cycles. The Fund trades on the TSX under the symbol SHN.UN.

Our investors received a **42% total return** in 2003

Financial and Operating Highlights

	2003	2002	% change
FINANCIAL (\$ thousands except per unit amounts)			
Oil and natural gas sales	\$ 242,157	\$ 142,661	70%
Net earnings	64,435	13,032	394%
Cash flow before change in non-cash working capital	136,038	68,243	99%
Distributable income	122,287	69,607	76%
Distributions per Trust Unit	2.85	2.16	32%
Acquisition and development costs	179,760	63,144	185%
Long term debt	121,691	115,283	6%
Unitholders' equity	366,241	266,432	37%
OPERATIONS			
Daily Production			
Oil (bbl/d)	2,023	2,054	(2)%
Natural gas (mmcf/d)	74.9	64.2	17%
Natural gas liquids (bbl/d)	2,252	1,454	55%
Oil equivalent (boe/d)	16,759	14,214	18%

29% **annual** compound rate of return
since mid-1996

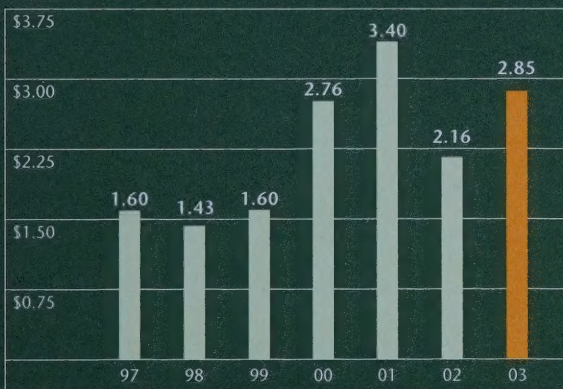


The highest among our peers

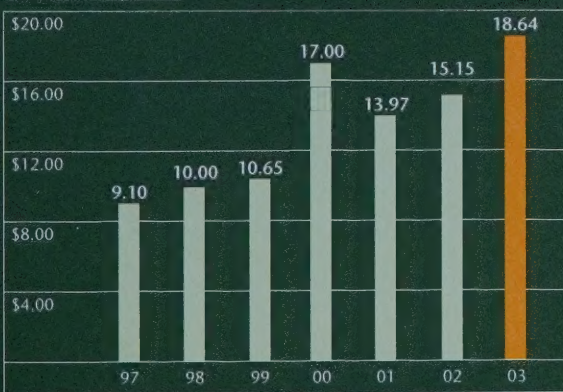
Standing the test of time

Since the Fund was formed in mid-1996, our unitholders have received a 29% annual compound rate of return – the highest among our peers. Year-to-year, our distributions closely track natural gas prices, so they reflect changes on North American gas markets. Our active management of the Fund continues to generate superior rates of return.

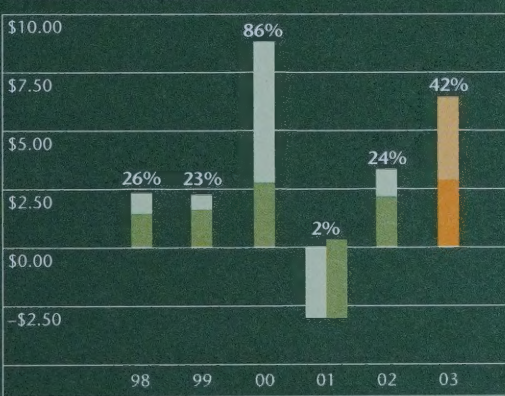
ANNUAL CASH DISTRIBUTIONS
(\$ per unit)



PRICE PER TRUST UNIT
December 31 (\$ per unit)

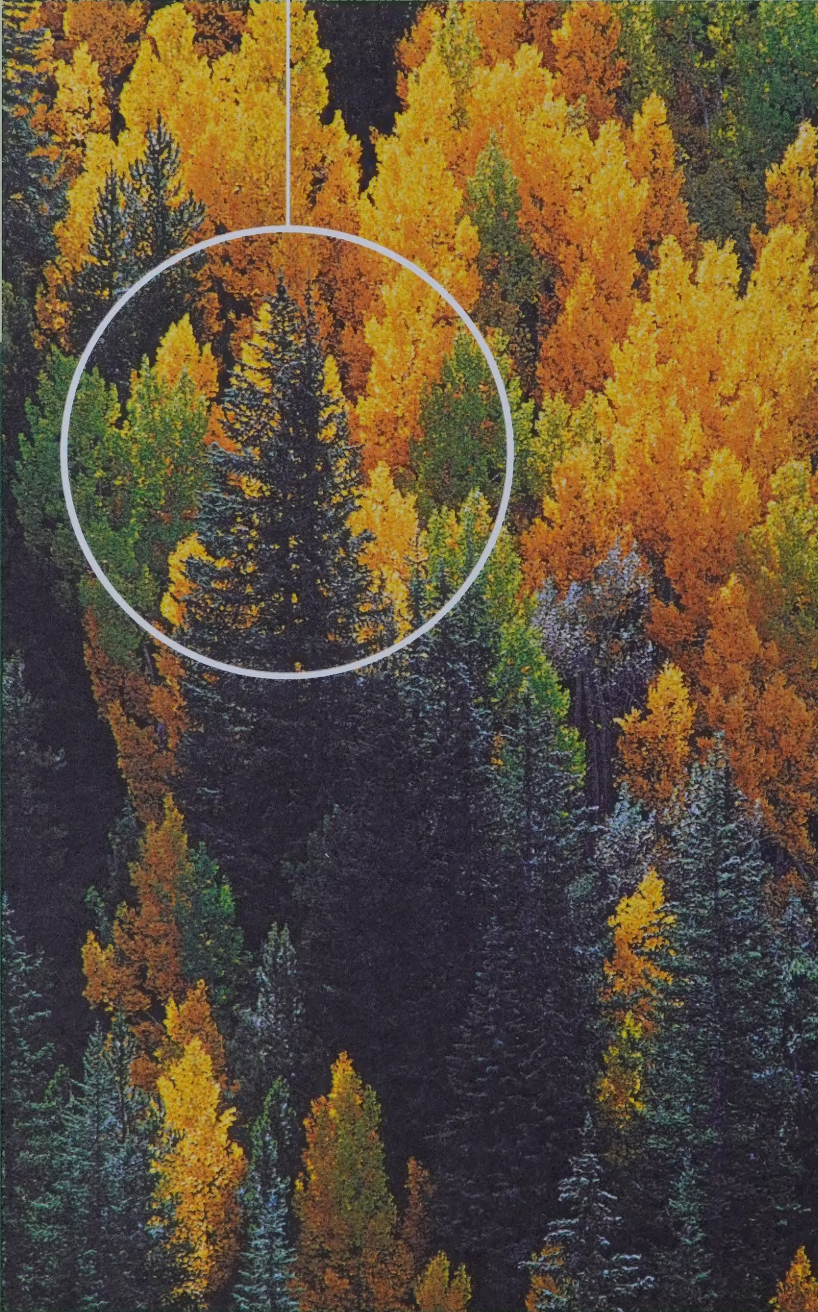


TOTAL RETURN BREAKDOWN

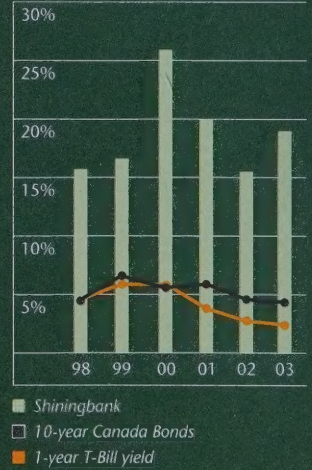


Change in unit price
Cash distributions per unit

A top performer vs other energy trusts and investments



SHININGBANK CASH
DISTRIBUTION RETURNS
Versus 10-year Canada Bonds
and 1-year T-Bill yield



Fellow Unitholders

It was definitely a good news year for Shiningbank. In 2003, our investors received a 42% total return, the second highest annual return since our inception in mid-1996. Our cash distributions were also the second highest in our history at \$2.85 per unit. The cash sent to our unitholders made up 19% of the 42% total return. The remaining 23% came from very healthy growth in our unit price.

We are particularly pleased in our performance considering that Shiningbank is a relatively low risk investment. By comparison, the TSX began to rebound rising 27% in 2003, but there was still a good deal of risk and volatility. There was better news. Shiningbank continues to lead the trust sector with the highest returns over time. For the past 7½ years, we have generated a 29% compound annual rate of return. We call it *standing the test of time*.

STRATEGIES FOR SUCCESS

Our track record of leading the sector in long-term investment returns rests on a few fundamentals that were established when Shiningbank was formed. We operate using the same strategies today.

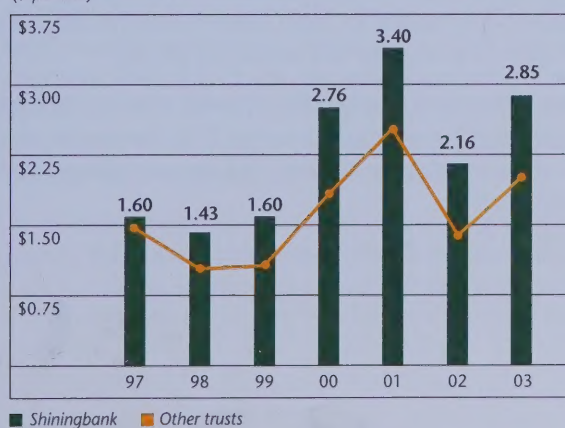
Shiningbank is primarily a natural gas producer. We have one of the highest percentages of natural gas in the sector – 74% of production. Our investors tend to be people who want exposure to the upside of natural gas prices as part of their portfolio. Yet they also want the relatively low risk of a trust. Shiningbank has consistently delivered both.

Gas prices have seen ups and downs over the years, and some startling extremes in both directions. We work to capture pricing highs and, where possible, we hedge volumes to soften the lows. That has led to our consistently strong distributions – and a following of investors who support our unit price.

The low risk factor comes into play with the quality of the assets we buy and our risk management strategies. We acquire oil and gas properties with a secure base of production and long reserve life. We concentrate our properties in areas where reserve quality is high and operating costs are low. This mitigates the downside when commodity prices fall.

We grow through acquisitions, but we only acquire properties that make economic sense. Our production has grown steadily every year, and we consistently add new reserves to replace our annual production, often by a large margin. Those are a few of the fundamentals that have made the Fund a top performer. We have accumulated a lot of evidence that our strategies are standing the test of time.

**SHININGBANK ANNUAL CASH DISTRIBUTIONS
VERSUS INDEXED AVERAGE OF OTHER OIL AND GAS TRUSTS**
(\$ per unit)



2003 PRODUCTION GROWTH

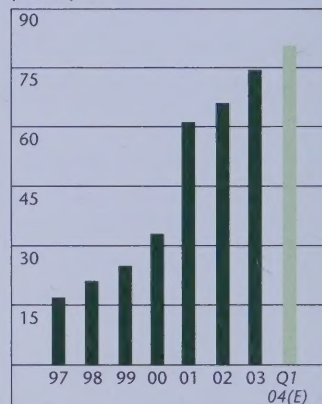
Total average production increased 18% over 2002 to 16,759 boe/d, largely due to the acquisition of properties at Ferrier/O'Chiese in west-central Alberta at the end of March. The acquisition added 3,300 boe/d, with 74% being NGL-rich natural gas. Besides the immediate production growth, we liked the properties' long reserve life of 9.5 years and the development potential for adding production. Soon after acquiring the properties, we began a program of low risk development drilling and results have exceeded our expectations. By year end, we had drilled nine successful wells and production from the property now exceeds 4,100 boe/d.

2004 PRODUCTION INCREASE

On March 8, 2004, we completed a corporate acquisition that will add 4,600 boe/d by the end of the first quarter. The \$175 million acquisition of Birchill Resources Limited, a private oil and gas company, involved the purchase of high working interests in a mix of operated and non-operated properties. About 80% of the production is natural gas and NGL, and the reserve life index is 8.3 years. We were particularly attracted to the deal as 40% of the production is from Ferrier, adjacent to the operations we acquired early last year. We are now in a position to expand our highly successful development drilling program in the area.

The acquisition is expected to add approximately \$37 million in annualized cash flow in 2004. Unitholders will begin to see the impact on cash flow in the second quarter 2004.

AVERAGE DAILY
NATURAL GAS PRODUCTION
(mmcf/d)



Our production has grown steadily every year and we consistently add new reserves to replace our annual production, often by a large margin.

COMMODITY PRICES

Our distributions rely heavily on commodity prices. Last year and to date in 2004, we have seen strong prices for both oil and natural gas. In 2003, our average price for all commodity sales was 44% higher than in 2002, with natural gas being particularly strong.

For 2003, our gas price averaged Cdn\$6.82 per mcf, up 58% from 2002. In early 2004, we could see prices weaken toward the end of winter, which is a normal seasonal effect. But, with the high level of demand in North America and ongoing concerns about supply, we expect healthy pricing in 2004. Our forecast is for gas to be selling in the range of Cdn\$5.00 to \$6.00 per mcf for much of the year.

Oil prices remained strong through 2003, a trend we expect to continue this year. In 2003, our average crude oil price was up 5% over 2002, and the NGL average price increased 27%. However, we are paid for our oil in US dollars, and the weak US dollar is reducing our revenues. Still, we agree with many analysts who are calling for oil to average US\$30/bbl this year.

DEALING WITH A COMPETITIVE WORLD

We regularly meet with unitholders, brokers and analysts across the country, and we are always asked about changes in the investment landscape and in the oil and gas royalty trust sector. For the benefit of all unitholders, we will address some of those questions here and outline where we see risks – and rewards.

Issue: *There is competition for investment dollars. Royalty trusts are fairly new on the investment scene – not just in the oil and gas business, but in other industries as well. They have become popular in the last few years and investors have a lot of choice.*

Our take: In the overall market, Shiningbank has some immunity from the competition for investment dollars. We are a niche play. People looking for natural gas exposure look at Shiningbank, particularly if they want the comfort of a trust with a track record.

Our standing with the competition can be seen in the strength of our unit price. It is a good indication of investor support, plus our units are always in demand. A good example is the equity issue we completed in March 2004 at \$17.00 per unit as part of the funding of our Birchill acquisition. It was a “bought-deal” and the issue sold out quickly.

With our units in demand, they are a form of currency that can be used to lower the cost of acquisitions. When we acquire properties, bank debt is often used as part of the funding strategy. However, that debt is paid down when we issue equity. This keeps our balance sheet strong, and we are able to control our financing costs as we grow.

There is more competition within the oil and gas sector, especially considering the number of trusts created in the past few years. With the strength in commodity prices, all of the trusts are doing well. However, when the commodity price cycle heads back down, the weaker trusts will begin to fall by the wayside. We expect this to lead to consolidation in the sector, and an easing in the acquisition market.

Issue: *Fierce competition is continuing on the acquisition market, particularly for natural gas properties. Within the industry, natural gas is seen as the fuel of choice in North America for years to come, and trusts and oil and gas companies are looking to increase their asset base. As a result, gas properties are continuing to command high prices.*

Our take: The heat has come off gas properties a bit in the last two years as oil properties have been looking more attractive under strong pricing. But it is still difficult and expensive for us to buy gas producing properties. Some of the major companies are expected to start selling properties this year, which will open up the supply a bit, but competition will remain fierce. Quite frankly, we are used to that type of competition. We stay active in the market, and focus on properties where we can make money. And we make sure that when we pay for reserves, we are buying quality.

To determine quality, one parameter we use is a property's recycle ratio. Recycle ratios are discussed on page 22, but suffice to say that the ratio takes into account such features as the type of production, operating costs and the life of assets. It is a good indication of the value we will receive from a property.



Issue: Most trusts are turning to drilling to add production and reserves. In light of high prices for acquisitions, it can be a low cost option. Some trusts conduct extensive drilling, but investors should be aware that they are taking on a new level of risk – drilling risk.

Our take: Drilling can be a good way to increase value in a trust. Our drilling success at Ferrier/O'Chiese is one example. As the Fund has grown, we have started to drill more wells, but we have not changed the risk profile of the Fund.

We do not conduct exploration. We only drill low risk development wells within our existing areas. In 2003, we spent \$23 million on capital investments in our properties. Only 54% was for drilling new wells, or 9% of our cash flow, which is relatively low as the sector goes. That spending resulted in a very economic program, adding 3.7 million boe of reserves at a cost of \$6.16/boe.

Issue: To fund large drilling programs, some trusts are lowering their payout ratios, the percentage of cash flow that they pay in distributions to unitholders. Not only does this reduce the amount paid out in distributions, it increases the risk to investors as cash flow is being used to drill prospects with varying degrees of risk.

Our take: There is room in the sector for trusts with aggressive drilling strategies and a lower payout ratio. If drilling is successful, the rewards can be high – but there is much more risk. At Shiningbank, we believe in maintaining a relatively high payout ratio, while conducting a low risk development drilling program. Overall, we have distributed about 90% of our cash flow in distributions.

Based on our strategies, and the **strong outlook for commodity prices**, we expect that 2004 distributions will remain close to the amount paid in 2003.

AN IMPORTANT NOTE ON RESERVES...

At year-end 2003, we had increased proved plus probable reserves over 2002 by 22% to 57,395 mboe, after taking into account our 2003 production and revisions. However, new regulations have changed the definitions of proven and probable reserves. Beginning with the 2003 year-end reserve report, all oil and gas companies were required to reclassify reserves.

The effect on Shiningbank was relatively small. There was a net 3% positive revision to our proved plus probable reserves – what used to be called established reserves. The biggest impact was the revision of our proved reserves where we recorded a 9% reduction as certain reserves were shifted into the probable category. When reviewing our reserve statistics, be aware that the entire industry is undergoing the same reclassification.

It is interesting to note that regulators introduced the changes to raise investor confidence in the reserves estimates of public oil and gas entities. Ironically, it had the opposite effect early in 2004. When word went out that reserves were being reclassified, investor confidence weakened and all oil and gas trusts saw their unit prices decline. We believe investors will regain confidence once the reclassification issue is better understood.

OUTLOOK

Our strategies are standing the test of time. We are known as a natural gas player and will maintain that focus. We will also stick to acquiring high quality, natural gas properties with a focus on west-central Alberta. We are looking at both new core areas in the region, and acquiring assets near our existing properties where there are synergies for day-to-day operations and cost control. Lastly, we will continue to do more development drilling to enhance our properties, but our programs will remain low risk development plays.

Based on our strategies, and the strong outlook for commodity prices, we expect that 2004 distributions will remain close to the amount paid in 2003. Commodity pricing is always volatile, but our goal is to provide unitholders with a reliable and secure investment.

IN CLOSING

Our employees are a group of dedicated and hard working professionals. It is through their efforts that Shiningbank has been a top performer since its inception. I would like to personally thank everyone for their contributions. It is through their efforts that we can all look forward to another successful year.



David M. Fitzpatrick

President and Chief Executive Officer

March 15, 2004



Corporate Governance

The bottom line in corporate governance is the protection of unitholders' interests. In theory, corporate governance encompasses the accuracy and openness of our finances and business transactions, and extends to how we run our operations in the field. In practice, corporate governance is a measure of integrity. It is a matter that we take seriously.

OUR COMMITMENT

The past year has seen a number of new reporting requirements set out by security regulators and by the Canadian Institute of Chartered Accountants. In some areas, the new requirements have increased our internal costs, but we are committed to meeting and exceeding the new requirements, and continuing to monitor our internal systems to ensure our reporting is of the highest standards.

FINANCIAL REPORTING

We take full responsibility for the Fund's financial results and our reporting to unitholders and regulatory agencies, including the TSX and various provincial authorities. Full disclosure is important, and our results are clearly presented on our financial statements. Those statements are prepared internally, reviewed by the Audit Committee which is comprised of independent directors, and audited by an independent firm of chartered accountants.

BOARD OF DIRECTORS

We have a small Board, but it is highly experienced and efficient. The majority of our directors are independent of management, which is one of the new recommendations coming forward. At Shiningbank, independent directors have always made up the majority of our Board. We believe that an outside perspective is important to our operations, our acquisitions and our financial reporting. The Board of Directors has three committees, all comprised of independent directors.

Audit Committee

The Audit Committee reviews quarterly and year-end disclosures and provides recommendations to the Board. The committee also monitors internal controls and risk management activities, and meets directly with our external auditors to review their findings.

Environmental, Reserve Review and Corporate Governance Committee

This committee reviews our year-end reserve evaluation prepared by independent engineers. Only after a thorough assessment is the reserve report brought to the Board for review and approval. This committee also reviews our environmental performance and compliance with corporate governance legislation.

Compensation Committee

The independent directors on this committee research and recommend reasonable compensation for management and directors. Their recommendations are reviewed annually by the Board.

ENVIRONMENT, HEALTH & SAFETY (EH&S)

Environmental protection and high standards of health and safety are ingrained in Shiningbank's field operations. Prior to acquiring a property, we assess it for safety or environmental liabilities and, with non-operated properties, we review the EH&S record of the company that will be in control. For our operated properties, our focus on sound operations has led to a safety record above the industry standard. In 2002, Shiningbank was recognized for its commitment to reducing climate change with a Gold Champion Level Reporter award from Canada's Climate Change Voluntary Challenge and Registry.

From left

EDWARD W. BEST

DAVID M. FITZPATRICK

TERRY P. PROKOPY

ARNE R. NIELSEN

GREGORY D. MOORE

WARREN D. STECKLEY

D. GRANT GUNDERSON

BRUCE K. GIBSON

Directors and Management Team



EDWARD W. BEST

Director

Ted has 50 years experience in the industry including being President of the Oil and Gas Division and a director of BP Canada. He has been a consultant in the domestic and international petroleum industry, and a director of a number of senior and junior oil and gas companies. Ted is an inductee into the Canadian Petroleum Hall of Fame and is an Honourary Member of the Canadian Society of Petroleum Geologists.

DAVID M. FITZPATRICK

*President and
Chief Executive Officer*

Dave is a geological engineer who brings considerable technical expertise to the role of President and Chief Executive Officer. This skill is combined with over 20 years industry experience, much of it in senior management with some of the industry's largest public companies. Dave is on the Board of Governors of the Canadian Association of Petroleum Producers.

TERRY P. PROKOPY

Vice President, Land

Terry has 30 years of top-level land experience working for both major and junior companies in Western Canada. Terry plays a key role in identifying and evaluating acquisition targets for the Fund.

ARNE R. NIELSEN

Chairman

Arne is one of the pioneers of the Canadian oil and gas industry. He has over 50 years experience in the industry including 10 years as President of Mobil Oil Canada Ltd. His contributions have been honoured in many ways including: inductee into the Canadian Petroleum Hall of Fame, an Honourary Doctorate from the University of Alberta, and he was named to the list of Albertans who had an impact on the 20th century.

GREGORY D. MOORE

Vice President, Operations

As a petroleum engineer, Greg has over 30 years experience working with senior and junior companies in both Canada and Australia. With responsibility for all field operations – from drilling to reservoir management – he has a broad base of technical expertise encompassing production optimization and reservoir performance.

WARREN D. STECKLEY

Director

Warren combines extensive oil and gas experience with financial and investment expertise. He is currently President and Chief Operating Officer for Barnwell of Canada, Limited, an oil and gas company and wholly-owned subsidiary of Barnwell Industries Inc., a public company that trades on the American Stock Exchange. He is also a director of several private and public oil and gas companies.

D. GRANT GUNDERSON

Director

Grant's extensive industry experience ranges from Vice-President, Economics and Planning for Canadian Superior Oil Ltd. to Manager of the heavy oil division for Mobil Oil Canada, and working with Mobil in a planning capacity in New York and Fairfax, Virginia.

BRUCE K. GIBSON

*Vice President, Finance
and Chief Financial Officer*

With over 25 years industry experience, Bruce has been the senior financial executive in several gas-weighted public companies. His extensive expertise includes hands-on oil and gas financial management, commodity marketing and public equity market issues.

Understanding Your Investment

The Fund’s high investment returns are
rooted in a **focus on natural gas**.



74% gas
production

Our **solid** foundation

Our Fundamentals

From the Fund's inception in mid-1996, we have operated with four fundamental strategies. These guiding principles have been our foundation for growth both operationally and financially. Based on our investment returns, we believe our strategies are standing the test of time.

NATURAL GAS

Shiningbank has always concentrated on the acquisition, production and sale of natural gas. At the start, we believed that the supply and demand scenario unfolding in North America would make natural gas the best long-term investment of all the fossil fuels. Today, the market fundamentals look even better than when the Fund was formed.

QUALITY ASSETS

We acquire quality assets that are immediately accretive to unitholders. Quality assets contribute to both the stability and sustainability of the Fund. We have built a base of properties with stable production characteristics and long-life reserves. As experienced oil and gas operators, we continually focus on cost control and optimizing production and reservoir performance.

STRONG BALANCE SHEET

Shiningbank's growth through the years has only been possible through the prudent management of our balance sheet. We are conservative in our use of debt. Over the longer-term, active management of our debt/equity structure has provided the foundation for strong distributions.

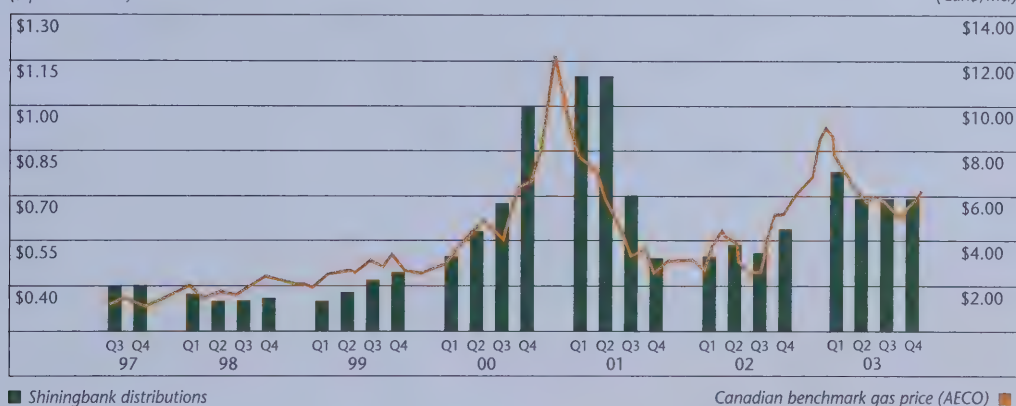
CREDIBLE MANAGEMENT

We are very much hands-on managers. From overseeing our operations in the field to the search for accretive acquisitions, the management team is actively involved in daily management of the Fund. We all share the same vision in growing the Fund, and the results can be seen in our track record of growth and our investment returns.

SHININGBANK'S DISTRIBUTIONS TRACK GAS PRICES

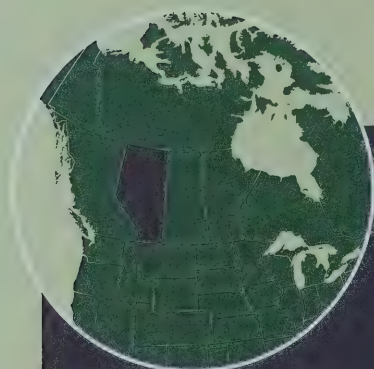
(\$ per Trust Unit)

(Cdn\$/mcf)



Quality Asset Base

Shiningbank is a **low risk energy investment** due to the types of assets we buy.

**DUNVEGAN**

Average 4.2% working interest in 140 wells (5.8 net); net 2.6 mmcf/d and 142 bbl/d oil and NGL. 30 year production history. Production comes from as many as seven pay zones.

WHITECOURT

42 gas wells (22.7 net) and one oil well (1.0 net). 54% average working interest. The Fund operates the gas plant. 9.0 mmcf/d gas production and 68 bbl/d oil and NGL.

PADDLE RIVER

37% interest in 35 wells (18.0 net). Net production of 3.4 mmcf/d and 210 bbl/d of oil and NGL. The NGL-rich gas averages 44 barrels of NGL per 1 mmcf of gas.

FERRIER/O'CHIESE

Acquired last year boosting 2003 gas production by 27%. Low risk drilling has exceeded expectations adding 4.0 mmcf/d. Production is 14.0 mmcf/d and 896 bbl/d of oil and NGL. 48% average working interest in 60 wells (30.7 net).

CAROLINE

Average 56% working interest in 34 oil wells (24.7 net) and 13 gas wells (4.9 net). Net production of 3.5 mmcf/d and 438 bbl/d of oil and NGL.

QUALITY PROPERTIES

The quality of our assets has a direct impact on our monthly distributions – and the Fund's longevity. That requires that we adhere to strict acquisition criteria. We target natural gas properties with high quality, stable production and a long reserve life that will stand the test of time.

LOWER RISK PROPERTIES

Oil and gas can be a risky business. Yet Shiningbank is a low risk energy investment due to the types of assets we buy. Our asset base is comprised of properties with a long and stable production history, a long reserve life and a low cost structure.

BEING IN CONTROL

We operate about 65% of our production. As operator, we control where our production is sold and how a property is managed and developed. We also control capital and operating costs. The concentration of our assets in west-central Alberta was a strategic move to provide ready access to extensive pipeline and processing infrastructure, which helps keep our costs low.

STABLE PERFORMANCE

Most of our properties have been producing for many years, and the geology is well understood. That history and technical data give us a good sense of what to expect in terms of production rates, reservoir performance and reserve life.

Any property we buy must have stable production. But the term can be misleading. Production from all oil and gas reservoirs declines every year, basically because the pressure in a reservoir falls and less hydrocarbons are forced to the surface. A 17-20% annual decline is fairly typical for gas properties in Alberta. Our annual decline rate is about 13%, which is a good indication of the quality of our assets – and the stability of our production.

PREMIUM-PRICED PRODUCTION

Most of our natural gas and crude oil commands premium pricing. Much of our gas is rich in NGL, such as butane or propane. The NGL is stripped out during processing and sold separately, which increases our netbacks. The majority of our oil production is light oil, which receives a higher price than heavier grades and is always in demand by refineries.

LOW RISK DRILLING

As we acquire more properties with development upside, we are moving to more development drilling. We do not explore for oil or gas. We drill infill wells into an existing pool to improve production and add reserves. We also drill step-out wells, which are drilled near a known pool to extend the reservoir. Development drilling can be a low-cost option for adding production and reserves when competition on the acquisition market makes properties too costly to buy.

The Gas Market

DEMAND

Natural gas has a healthy outlook for years to come. The US is the world’s largest consumer, and forecasters agree that demand will continue to increase for decades. That bodes well for the price of natural gas, particularly as there are continuing concerns about supply.

The seasonal cycle

Gas prices tend to be higher in the winter due to the demand for heating. Last year, Shiningbank’s gas price averaged Cdn\$6.82 per mcf. But that includes some wide swings in seasonal pricing.

Gas prices in North America are largely set on the NYMEX exchange. In March 2003, gas was selling on the NYMEX at about Cdn\$13.00 per mcf, only to fall to a low of about Cdn\$5.00 per mcf in October. That volatility comes from the market’s perception of adequate supply. One of the the best indicators of supply is the amount of natural gas in storage.

Volumes in storage

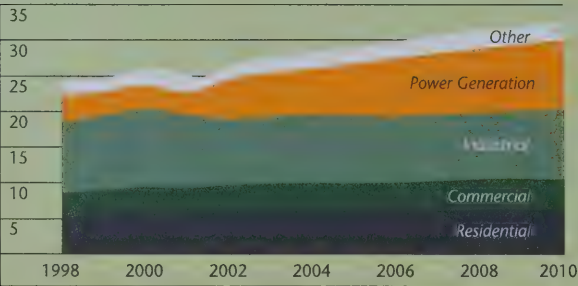
Large volumes of natural gas are stored in underground caverns across Canada and the US. Based on US demand, there is about seven weeks of supply when storage is filled to capacity.

Each summer, these facilities are filled in preparation for the high demand winter season. During the summer injection season, gas prices tend to be lower.

Price volatility

A single stretch of severe winter weather can force up the price of gas. When a blizzard hits the US East Coast, heating demand will rise. In turn, gas prices will be driven up by major buyers, such as utilities, gas-fired electricity plants, food processors, or steel makers. They simply need to ensure adequate supply to keep operating. When prices get too high, some industries reduce activity or close down temporarily. This eases the pressure on supply and prices soften.

NORTH AMERICAN
NATURAL GAS DEMAND GROWTH
(tcf)



Source: Natural Resources Canada

The same supply concerns can support prices during the summer storage injection season, as occurred last year. The cold winter had drawn down storage to very low levels. Concerned about having enough supply for the upcoming winter, major gas buyers began locking in contracts at higher than normal prices. The pricing low point for the year was in October when the market felt that storage was adequately refilled to meet winter demand.

SUPPLY

Maturing resource base / New sources of supply

Many gas fields in North America are mature. New wells are producing less gas, and production rates are declining faster than in the past. Over the next 10-20 years, analysts predict that new, higher cost sources of supply will be required. In the mature basins, new technologies will have to be developed to get more volumes out of lower productivity reservoirs. Pipelines are being planned to deliver gas from Alaska and Canada's Mackenzie Delta. And new US terminals are proposed to increase imports of Liquefied Natural Gas (LNG).

ARCTIC GAS

A pipeline to move gas from the Mackenzie Delta is planned for about 2010, and a proposed pipeline from Alaska could see gas flowing by about 2015.

MAJOR EXPORTER

Canada is the world's third largest producer of natural gas and the second largest exporter. Annual production is 6.4 trillion cubic feet, of which 3.8 tcf is exported to the US.

COAL BED METHANE (CBM)

Coal seams buried underground emit methane, which is natural gas. Wells can be drilled down to the coal to produce this gas. This CBM production accounts for about 8% of total US production and projects are now being tested in Canada.

WORLD'S LARGEST CONSUMER

The US consumes about 26% of the world's production, or about 22 tcf a year. Approximately 82% is produced in the US. Canada supplies 16% and 2% is shipped to ports as LNG.

WHERE IS GAS STORED?

Natural gas is mostly stored in old depleted oil and/or gas reservoirs located near consuming markets. Some gas is stored in aquifers or natural salt caverns.

LEGEND

 Liquefied Natural Gas Ports

Everett,
Massachusetts

Elba Island,
Georgia

Lake Charles,
Louisiana

SOURCES: Natural Gas Supply Association, Energy Information Administration, Natural Resources Canada, Canadian Association of Petroleum Producers, Mackenzie Gas Project

Acquisition 2003

Largest property acquisition to date

FERRIER/O'CHIESE

On March 31, 2003, we completed the largest property acquisition in the Fund's history. The \$133.3 million deal brought major production growth, significant reserves and opened up opportunities for cost reductions and production gains through low cost development activities. It was a prime example of our acquisition strategy in action.

MAJOR PRODUCTION GAIN

The immediate benefit was an estimated production increase of 3,300 boe/d for 2003. With 74% of that being natural gas, we increased our gas volumes by 27% in the second quarter, which was above our performance forecast for the acquired assets. By year end, production rates continued to surpass expectations. Ferrier/O'Chiese added nearly 4,100 boe/d, almost 20% more than we predicted at the time of the acquisition. The strong growth was from a successful program of low risk, development drilling and the performance of existing wells. That type of growth points to the high quality of the properties included in the deal.

QUALITY RESERVES

The quality of reserves was an attractive part of the acquisition. The reserve life index was 9.5 years, which is above average for gas fields in Alberta. Before we bought the properties, an evaluation by independent engineers estimated established reserves at 49.6 bcf. That increased our gas assets by 24%.

We liked the quality of the properties, and were prepared to pay more than in the past. The purchase price equated to \$11.68 per established boe, which reflects the competitive market for properties, the quality of the assets and the robust outlook for natural gas prices.

We immediately moved to improve the economics of the deal by hedging a large amount of production at very high prices. These hedges alone will pay out approximately 40% of the purchase price by the end of 2004.

SUCCESSFUL DEVELOPMENT

The economics were further enhanced through active management of the properties and a program of development drilling.

The acquisition involved a package of assets adjacent to our existing landholding at Ferrier. As operator of 70% of the properties, we have reduced operating costs through such synergies as more efficient use of gas plants and other infrastructure.

The majority of the development was low risk drilling. Soon after the acquisition, we began to participate in low-risk development wells, and results have exceeded our expectations. In 2003, nine wells (4.2 net) were drilled – all successful. By year end, they were producing 4.0 mmcf/d. Up to seven more wells could be drilled before mid-2004.



Large corporate **acquisition**

ACQUISITION OF BIRCHILL RESOURCES LIMITED

On March 8, 2004, we closed our second largest corporate acquisition to date – the \$175 million purchase of a private oil and gas company, Birchill Resources Limited. Unitholders will begin to see the effects on cash flow in the second quarter.

MAJOR PRODUCTION GROWTH

We have acquired high working interests in a mix of operated and non-operated properties, with 80% of production being natural gas and NGL. At time of writing, we anticipate production growth of over 20% by the end of the first quarter.

FERRIER AREA EXPANDS

One attractive part of the deal was that 40% of the production is from Ferrier, which is adjacent to the Ferrier/O'Chiese properties we acquired early last year. Our greater presence in the area will allow more efficient production optimization and cost reductions – and increased opportunities for low risk development drilling. The drilling potential at Ferrier, and in other areas, was enhanced with the inclusion of 72,300 net acres of undeveloped lands and a large inventory of seismic data.

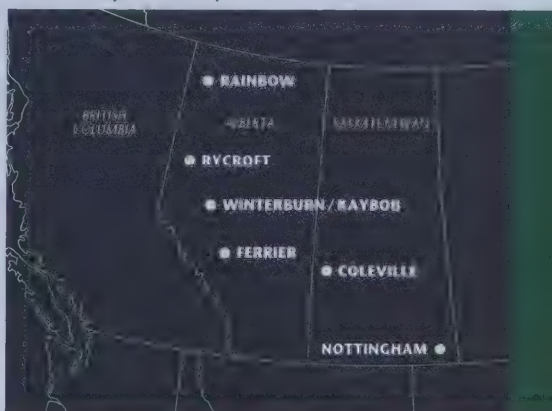
The acquisition is expected to **increase production by 20%** late in first quarter 2004, 80% natural gas and NGL.

Several properties in the package are located outside of our west-central Alberta focus. As happens in a corporate acquisition, we were required to purchase the entire package of properties up for sale. Over time we expect to rationalize some of these non-core assets.

QUALITY PROVEN RESERVES

Shiningbank's internal assessment of the acquired reserves totalled 13,997 mboe, with 71% being proved. That estimate is 21% lower than Birchill's independent evaluation and is based on our experience in the area and our conservative mindset in estimating reserves. The cost per boe equates to \$11.52, which is close to the \$11.68 we paid in our 2003 acquisition at Ferrier/O'Chiese. When adding in the cost of undeveloped land and seismic, the acquisition cost was \$12.50/boe. The Reserve Life Index on the properties is 8.3 years.

Birchill Properties Acquired



Reserves

MAJOR CHANGES THIS YEAR

Beginning with this year's annual report, all oil and gas trusts and energy companies are required to change the way they report reserves. The new regulations, known as NI 51-101, issued by the Canadian Securities Administrators require a more stringent definition of reserves. The good thing is that all trusts and oil companies are making the change at the same time. The bad thing is that it has caused concern among investors.

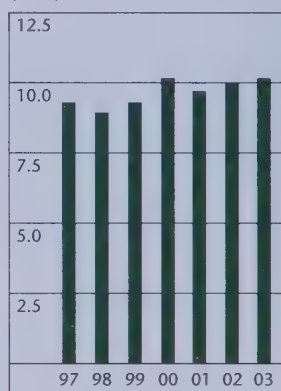
The proved reserves of most producers in Canada have not "disappeared" – they have been recalculated using more conservative methods. Shiningbank had no reserve write-downs this year. Neither has there been any changes in reservoir performance on any of our major assets. Our properties are performing as reliably as always.

The most significant change is that the definition of "proved reserves" has become more conservative. Some of the volumes previously reported as proved are now included in the probable category. Also, probable reserves must now be reported on a risked basis whereas they were reported unrisked before. The old "established" category is the equivalent of the new proved plus probable category.

RESERVE LIFE INDEX

The reserve life index (RLI) refers to the numbers of years that we can continue to produce at the current level of production. At the end of each year, we calculate the RLI by dividing the proved plus probable reserves by our expected annual production. For 2003, that was 57.4 million boe divided by 5,600 boe/d, or 10.1 years.

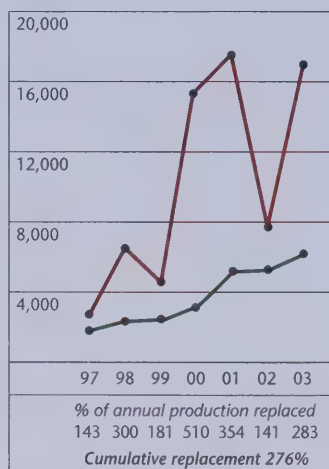
RESERVE LIFE INDEX
(Years)



RESERVE REPLACEMENT

Reserve replacement refers to new reserves added each year to replace our annual production. It is a good measure of how well a trust is growing its asset base. Our reserve replacement changes from year to year as we acquire assets when the price and timing are right, and when we identify quality properties that are a good fit with our asset base. When we find the right acquisition, we replace production by a wide margin.

RESERVE REPLACEMENT
(mboe)



■ Annual production
■ Reserve additions (excluding disposals)

SUMMARY OF RESERVES

The Fund's oil and gas reserves were independently evaluated by Paddock Lindstrom & Associates Ltd. at December 31, 2003, in accordance with NI 51-101. The Fund's Reserve Committee met with the reserve evaluators to review their findings and procedures and the reserve report was accepted by the Board.

Summary of Oil and Gas Reserves – Forecast Prices and Costs

<i>Reserves (Company Interest)</i>				
<i>As at December 31, 2003</i>	<i>Oil (mdbl)</i>	<i>Natural Gas (mmcf)</i>	<i>NGL (mdbl)</i>	<i>Oil Equivalent (mboe)</i>
Proved				
Developed producing	4,234.1	159,078.6	5,104.9	35,852.1
Developed non-producing	120.1	14,253.3	350.4	2,846.1
Undeveloped	218.6	9,530.4	546.4	2,353.4
Total proved	4,572.8	182,862.3	6,001.7	41,051.6
Probable	2,213.8	70,091.2	2,448.0	16,343.6
Total proved plus probable	6,786.6	252,953.5	8,449.7	57,395.2

These volumes include working interest plus royalty interests attributable to the Fund.

The 2003 reserve data is not directly comparable to historical data due to the new reserve definitions and evaluation methodology under NI 51-101. Previously, reserves were evaluated in accordance with National Policy 2-B. There are numerous differences between these two sets of standards, including new confidence thresholds involving the recovery of proved plus probable reserves.

Value of Reserves Using Forecast Prices and Costs

<i>Discount Factor</i>			
<i>As at December 31, 2003 (000s)</i>	<i>0%</i>	<i>10%</i>	<i>12%</i>
Present value of reserves			
Proved	\$ 700,056	\$ 448,019	\$ 420,834
Probable	270,205	98,131	85,303
Total proved plus probable	\$ 970,261	\$ 546,150	\$ 506,137

The present value of reserves is calculated based on price forecasts prepared by Paddock Lindstrom & Associates Ltd. in its December 31, 2003 evaluation.

Forecast Price Assumptions

<i>Oil</i>		<i>Gas</i>		
<i>As at December 31, 2003</i>	<i>WTI US\$/bbl</i>	<i>Edmonton Light C\$/bbl</i>	<i>AECO C\$/mmbtu</i>	<i>Alberta Reference C\$/mmbtu</i>
2004	\$ 29.00	\$ 37.61	\$ 6.00	\$ 5.70
2005	26.50	34.25	5.31	5.07
2006	25.50	32.90	4.83	4.64
2007	25.00	32.21	4.87	4.68
2008	25.50	32.85	4.92	4.73
2009 – 2012	+2%/annum	+2%/annum	+1%/annum	+1%/annum
Thereafter	+2%/annum	+2%/annum	+2%/annum	+2%/annum

Our costs to grow

ACQUISITION COSTS

The property acquisition market has been highly competitive in the past few years. Natural gas properties in particular have been commanding high prices as trusts and oil and gas companies try to take advantage of strong pricing today – and the strong longer term outlook. Our acquisition costs in 2003 were \$11.70 per boe of proved plus probable reserves, up from \$10.11 in 2002.

DEVELOPMENT COSTS

In 2003 we spent \$12.4 million on drilling and other development activities. We participated in a total of 48 wells (10.6 net) and our success rate was 100%. We had an especially rewarding program at Ferrier and O'Chiese where nine wells (4.2 net) were drilled. In total, our drilling program added 3,700 mboe of proved plus probable reserves for a development cost of \$6.16 per boe.

We also spent \$10.5 million on other development activities to both improve production and lower operating expenses. The majority of the money was spent on upgrading existing production and well facilities and some minor land purchases.

COSTS PER BOE OF PROVED PLUS PROBABLE RESERVES

	2003	2002 ⁽¹⁾	2001 ⁽¹⁾	Three-year average
Acquisition costs	\$ 11.70	\$ 10.11	\$ 13.70	12.27
Development costs	6.16	13.27	17.94	8.91
Total acquisition and development ⁽²⁾	11.07	10.54	14.94	12.57
Operating netback per boe	\$ 24.19	\$ 16.31	\$ 20.92	20.68
Recycle ratio (netback ÷ acquisition and development costs)	2.2	1.5	1.4	1.6
Reserve replacement (% of production)	283%	141%	354%	259%

⁽¹⁾ For years prior to 2003, established reserves are quoted.

⁽²⁾ Total acquisition and development costs include changes in estimated future development costs for that year.

RECYCLE RATIO

A recycle ratio is calculated by taking the operating netback and dividing by the acquisition and development costs. Netback takes into account the quality of the production by using an actual sales price. Then actual expenses are deducted for operating costs and royalties. Reserve replacement costs include the money spent to replace a barrel of oil equivalent and all capitalized costs associated with finding and acquiring reserves, not including dispositions.

Recycle ratios are a good measure of how cost-effective a trust is at replacing reserves. Our recycle ratio for 2003 was 2.2 to 1. This shows that the acquisitions and development for the year were accomplished at very economic prices.

Management's Discussion and Analysis

Boe volumes are reported at 6:1 with 6 mcf = 1 bbl.

Results of Operations

PRODUCTION VOLUMES

Daily Production Volumes

(000s)	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Oil (bbl/d)	2,018	1,886	7%	2,023	2,054	(2)%
Natural gas (mmcf/d)	76.6	62.2	23%	74.9	64.2	17%
NGL (bbl/d)	2,530	1,484	71%	2,252	1,454	55%
Oil equivalent (boe/d)	17,311	13,743	26%	16,759	14,214	18%
Natural gas % of total production	74%	75%		74%	75%	

Fourth quarter daily average production grew 26% over fourth quarter 2002. Year over year, Shiningbank achieved 18% volume growth. Both of these increases were primarily due to the Ferrier/O'Chiese acquisition at the end of first quarter 2003, offset in part by the natural declines of producing properties that are estimated to average 13% per year.

PRICING (INCLUDING HEDGING ACTIVITY)

Average Prices – After Hedging

	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Average Prices						
Oil (\$/bbl)	\$ 33.62	\$ 38.92	(14)%	\$ 37.95	\$ 36.31	5%
Natural gas (\$/mcf)	\$ 6.14	\$ 5.36	15%	\$ 6.82	\$ 4.32	58%
NGL (\$/bbl)	\$ 32.93	\$ 33.28	(1)%	\$ 33.65	\$ 26.59	27%
Oil equivalent (\$/boe)	\$ 35.90	\$ 33.31	8%	\$ 39.59	\$ 27.50	44%
Benchmark Prices						
WTI (US\$/bbl)	\$ 31.21	\$ 28.14	11%	\$ 31.04	\$ 26.08	19%
AECO natural gas (Cdn\$/mcf)	\$ 5.59	\$ 5.26	6%	\$ 6.70	\$ 4.07	65%

Natural gas

For the fourth quarter of 2003, Shiningbank's realized natural gas price averaged \$6.14/mcf, 15% higher than for the same period in 2002. Hedging increased the realized gas price by \$0.35/mcf for the quarter, compared with a hedging loss of \$0.02/mcf in 2002.

For the year 2003, Shiningbank's realized gas price increased 58% from 2002 reaching \$6.82/mcf. Hedging contributed \$0.11/mcf, versus a \$0.16/mcf gain in 2002. Benchmark prices in Alberta (AECO) rose 65% on average from 2002, primarily due to cold weather in the first quarter of 2003.

Gas pricing fundamentals remain strong. We expect that prices will weaken in first quarter 2004 with the end of winter, a normal seasonal effect. However, 2004 pricing should remain very strong with benchmark prices in the range of Cdn\$5.00 to \$6.00/mcf. High volatility will continue to be normal for the market. Shiningbank does not control the prices received for its production, but mitigates the market risk through various methods including hedges and geographical diversity. (See "Business Risks" on page 34.)

Oil

Realized oil prices for the quarter were \$33.62/bbl, down 14% from fourth quarter 2002 due to strength in the Canadian dollar. Hedging reduced the realized price by \$1.50/bbl compared with a hedging reduction of \$0.18/bbl in fourth quarter 2002.

Shiningbank's oil prices in 2003 rose 5% to average \$37.95/bbl. Hedging activities reduced the realized price by \$1.33/bbl as compared to an \$0.08 reduction in 2002. The benchmark West Texas Intermediate (WTI) price averaged 19% higher than in 2002, however, the weakness in the US dollar greatly reduced the impact of this strength. Oil prices are expected to remain high in US dollar terms, with many analysts calling for a US\$30/bbl average price this year.

Current hedging

Shiningbank maintains an active hedging program for both oil and gas production. During 2003, the Fund hedged an average of 25% of total gas production and 37% of total oil production, as compared to 30% and 24% respectively in 2002. Under the Fund's hedging policy, not more than one-half of production volumes can be hedged at any one time. Hedging is intended to stabilize cash distributions by protecting the price on a portion of the production portfolio. Currently, Shiningbank has the following hedging contracts in place:

<i>Period</i>	<i>Commodity</i>	<i>Volume</i>	<i>Price</i>
January 1, 2004 – March 31, 2004	Gas	5,000 GJ/d	\$6.00/GJ floor \$8.55/GJ ceiling
January 1, 2004 – December 31, 2004	Gas	11,000 GJ/d	\$6.11/GJ
April 1, 2004 – October 31, 2004	Gas	5,000 GJ/d	\$5.25/GJ floor \$6.67/GJ ceiling
April 1, 2004 – October 31, 2004	Gas	5,000 GJ/d	\$5.45/GJ floor \$6.32/GJ ceiling
April 1, 2004 – March 31, 2005	Gas	5,000 GJ/d	\$5.91/GJ
April 1, 2005 – December 31, 2005	Gas	5,000 GJ/d	\$5.00/GJ floor \$6.39/GJ ceiling
January 1, 2004 – September 30, 2004	Oil	500 bbl/d	US\$25.00/bbl floor US\$30.00/bbl ceiling
March 1, 2004 – December 31, 2004	Oil	500 bbl/d	US\$31.87/bbl
October 1, 2004 – December 31, 2004	Oil	500 bbl/d	US\$25.00/bbl floor US\$30.00/bbl ceiling

REVENUES

	Three months ended December 31,				Year ended December 31,			
	2003	% of Revenue	2002	% of Revenue	2003	% of Revenue	2002	% of Revenue
Oil sales	\$ 6,520	11%	\$ 6,785	16%	\$ 29,000	12%	\$ 27,276	19%
Natural gas sales	40,823	71%	30,821	73%	183,404	76%	97,476	68%
NGL sales	7,664	14%	4,545	11%	27,667	11%	14,106	10%
Hedging – Gas	2,402	4%	(64)	–	2,980	1%	3,823	3%
Hedging – Oil	(277)	–	(30)	–	(978)	–	(62)	–
Other	49	–	59	–	84	–	42	–
	\$ 57,181	100%	\$ 42,116	100%	\$ 242,157	100%	\$ 142,661	100%

The following table sets out the net effect on revenue of changes in commodity prices and volumes between 2002 and 2003.

Sales Variance Analysis – After Hedging

(000s)	Three months ended December 31,	Year ended December 31,
	2003/2002	2003/2002
Crude oil and NGL		
Volume increase	\$ 3,674	\$ 7,342
Price (decrease) increase	(1,067)	7,027
Increase	\$ 2,607	\$ 14,369
Natural gas		
Volume increase	\$ 7,073	\$ 16,811
Price increase	5,395	68,274
Increase	\$ 12,468	\$ 85,085

Higher revenues for the fourth quarter of 2003, and for the full year, were the result of higher natural gas volumes and prices. A drop in realized crude oil and NGL prices in the fourth quarter, due to exchange rates, slightly offset this effect.

ROYALTIES

	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Total royalties, net (000s)	\$ 12,794	\$ 9,031	42%	\$ 53,628	\$ 26,470	103%
As % of revenue	22.4%	21.4%	5%	22.1%	18.6%	19%
Per boe	\$ 8.03	\$ 7.14	12%	\$ 8.77	\$ 5.10	72%

Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners. The royalty rate was higher in 2003, mainly due to higher commodity prices under the price-sensitive rate structure for Alberta Crown natural gas royalties. The Fund expects that commodity prices in 2004 will be similar to those realized in 2003, resulting in little change to the 2004 realized royalty rate. The Alberta government provides a credit under the Alberta Royalty Credit program, which the Fund is eligible to access on a small portion of its properties. The Fund recorded the maximum credit of \$500,000 in both 2003 and 2002.

OPERATING COSTS

	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Operating costs (000s)	\$ 11,058	\$ 7,973	39%	\$ 40,536	\$ 31,583	28%
Per boe	\$ 6.94	\$ 6.31	10%	\$ 6.63	\$ 6.09	9%

Operating costs increased 10% on a boe basis from fourth quarter 2002, and 9% year over year. These increases were due to increasing field service costs arising from the high level of industry activity, and rising fuel and electricity costs. The Fund expects 2004 costs to be similar to 2003 on a per boe basis due to continuing upward pressure on field costs, aging of the property portfolio and the likelihood of higher energy costs in 2004, all of which are expected to offset efficiencies gained in the Fund's operations.

OPERATING NETBACKS

(\$/boe)	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Gross revenue	\$ 35.90	\$ 33.31	8%	\$ 39.59	\$ 27.50	44%
Royalty expenses (net of ARTC)	(8.03)	(7.14)	12%	(8.77)	(5.10)	72%
Operating expenses	(6.94)	(6.31)	10%	(6.63)	(6.09)	9%
Operating netback	\$ 20.93	\$ 19.86	5%	\$ 24.19	\$ 16.31	48%

Operating netbacks increased 5% quarter over quarter and 48% year over year. Strong commodity prices drove these increases, but the growth in netbacks was partially offset by higher royalties and operating costs per boe.

GENERAL AND ADMINISTRATIVE COSTS

	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
General and administrative costs (000s)	\$ 1,432	\$ 1,355	6%	\$ 4,649	\$ 4,143	12%
Per boe	\$ 0.90	\$ 1.07	(16)%	\$ 0.76	\$ 0.80	(5)%
Per average Trust Unit	\$ 0.03	\$ 0.04	(25)%	\$ 0.11	\$ 0.13	(15)%

General and administrative costs decreased 16% per boe from fourth quarter 2002, and 5% per boe year over year. The cost reductions on both a per boe and per average Trust Unit basis were due to efficiencies resulting from economies of scale. At year end, Shiningbank had 33 full-time employees and 22 full- and part-time consultants at its head office. Field and production staff consisted of one production superintendent, 20 full-time employees and 39 contract operators. Costs of field and production staff are included in operating expenses.

MANAGEMENT FEES

All management and acquisition fees were eliminated after October 9, 2002 as a result of the transaction that internalized the Fund's management.

INTEREST

	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Interest (000s)	\$ 1,093	\$ 1,330	(18)%	\$ 6,103	\$ 5,109	19%
Per boe	\$ 0.69	\$ 1.05	(34)%	\$ 1.00	\$ 0.98	2%
Per average Trust Unit	\$ 0.02	\$ 0.04	(50)%	\$ 0.15	\$ 0.16	(6)%

Interest expense, which includes bank charges, increased 19% year over year. This increase was the result of higher debt levels following the Ferrier/O'Chiese acquisition, higher annual renewal fees for the bank line of credit and higher interest rates. Fourth quarter 2003 interest expense dropped 18%, primarily due to lower interest rates and bank stamping fees.

At December 31, 2003, the Fund held an interest rate swap for \$10.0 million at an interest rate of 3.48% expiring October 30, 2004. All other debt bears interest at current short-term market rates.

DEPRECIATION, DEPLETION AND AMORTIZATION

	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Depreciation, depletion and amortization (000s)	\$ 21,879	\$ 15,234	44%	\$ 75,027	\$ 60,034	25%
Per boe	\$ 13.74	\$ 12.05	14%	\$ 12.27	\$ 11.57	6%

Depreciation, depletion and amortization rose 44% for the fourth quarter and 25% year over year, due to increased production volumes and higher acquisition costs. The fourth quarter depletion calculation was based on December 31, 2003 reserve estimates. Proved reserves decreased 9% from 2002 primarily as a result of changes to reserve definitions under National Instrument 51-101 ("NI 51-101").

INTERNALIZATION OF MANAGEMENT CONTRACT

	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Internalization of management contract (000s)	\$ 1,561	\$ 10,984	(86)%	\$ 5,989	\$ 10,984	(45)%
Per boe	\$ 0.98	\$ 8.69	(89)%	\$ 0.98	\$ 2.12	(54)%

Effective October 9, 2002, the Fund internalized its management by acquiring all of the shares of Shiningbank Energy Management Inc., the former manager of the Fund. Prior to the acquisition, the Fund paid fees of 3.25% of net operating income, a fee of 1.5% on the purchase price of acquisitions and a quarterly scheduled dividend in accordance with the terms of a management agreement. The acquisition resulted in the elimination of all future fees and dividends.

Of the total purchase price of \$20.6 million, \$11.0 million was deferred, representing Exchangeable Shares subject to escrow provisions, and is being amortized into income over specific vesting periods through 2007. During 2003, \$5.4 million (2002 – \$1.0 million) was expensed, representing the amortization of these escrowed Exchangeable Shares.

Total consideration for the internalization was reduced by \$1.8 million at the time of the transaction to provide for performance and retention bonuses to be paid to employees over the ensuing five years. During 2003, \$582,750 of this bonus pool was paid out in cash and included in internalization expenses. This compares with \$400,000 in 2002. The pool has \$817,250 remaining.

TRUST UNIT INCENTIVE COMPENSATION

	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Trust Unit incentive compensation (000s)	\$ 572	–	–	\$ 572	–	–
Per boe	\$ 0.36	–	–	\$ 0.09	–	–

During the fourth quarter 2003, the Fund elected to prospectively adopt the amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3870, "Stock-based compensation and other stock-based payments" for all rights issued on or after January 1, 2003. The fair value of rights issued was determined using the Black-Scholes model, and will be brought into income over the vesting period of the rights. The 2003 expense represents the fair value of the rights vesting within the year. (See "Financial Reporting" on page 33.)

TAXES

	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Capital and large corporation taxes (000s)	\$ 139	\$ 236	(41)%	\$ 595	\$ 665	(11)%
Future income tax expense (recovery) (000s)	\$ 807	\$ (2,660)	130%	\$ (12,443)	\$ (14,160)	12%
Per boe	\$ 0.59	\$ (1.92)	131%	\$ (1.94)	\$ (2.60)	25%

The Fund is obligated to pay provincial capital taxes and federal large corporations tax in its operating corporations. However, activities are managed so current income taxes are not payable in those entities.

On June 9, 2003, the federal government announced a five-year package of tax changes intended to lower tax on resource income for oil and gas producers. This package included decreased corporate income tax rates for resource activities, a full deduction for actual Crown royalties paid and the elimination of the existing 25% resource allowance. As a result, Shiningbank recorded a recovery of \$8.0 million of future taxes in second quarter 2003.

NET EARNINGS

Shiningbank's fourth quarter 2003 earnings were \$5.0 million or \$0.11 per Trust Unit (\$0.11 diluted). In fourth quarter 2002, the Fund recorded a loss of \$2.1 million or \$0.06 per Trust Unit (\$0.06 diluted).

For the year ended December 31, 2003, Shiningbank's net earnings were \$64.4 million or \$1.55 per Trust Unit (\$1.52 diluted). This compares with \$13.0 million or \$0.40 per Trust Unit (\$0.39 diluted – restated) in 2002. Higher commodity prices, higher production volumes and the \$8.0 million future tax recovery were partially offset by increased expenses.

DISTRIBUTABLE INCOME

Distributable income for 2003 increased to \$122.3 million from \$69.6 million in 2002 due to higher commodity prices and production volumes. On a per Trust Unit basis, distributions increased 32% to \$2.85 in 2003 from \$2.16 in 2002. The Fund paid out 90% of its cash flow in both 2003 and 2002, after removing the cash internalization costs.

Calculation of Distributable Income

(000s except Trust Unit amounts)	Three months ended December 31,			Year ended December 31,		
	2003	2002	%	2003	2002	%
Cash flow before change in non-cash working capital	\$ 30,082	\$ 17,661	70%	\$ 136,038	\$ 68,243	99%
Capital expenditures	(6,865)	(5,027)	37%	(22,931)	(11,867)	93%
Site restoration costs	(57)	(28)	104%	(218)	(385)	(43)%
Internalization of management contract	582	4,509	(87)%	608	4,509	(87)%
Working capital adjustments	6,887	2,801	146%	8,790	9,107	(3)%
Distributable income	\$ 30,629	\$ 19,916	54%	\$ 122,287	\$ 69,607	76%
Distributions per Trust Unit	\$ 0.69	\$ 0.60	15%	\$ 2.85	\$ 2.16	32%
Trust Units outstanding	44,343	33,194		44,343	33,194	

2004 Distributable Income Sensitivities

The sensitivity of distributions to commodity price variables is shown in the table below.

	(\$000s)	Per Trust Unit
US \$1 per bbl	\$ 1,300	\$ 0.03
Cdn \$0.25 per mcf	\$ 4,000	\$ 0.10
US \$0.01 exchange	\$ 2,600	\$ 0.05
100 bbl/d	\$ 750	\$ 0.01
1 mmcf/d	\$ 1,300	\$ 0.03
1% prime rate	\$ 1,300	\$ 0.03

Note: These sensitivities take into account the issue of 8,800,000 new Trust Units in March 2004 and production volumes acquired in March 2004.

INCOME TAX INFORMATION

In 2003, 69.84% of cash distributions paid by the Fund were required to be included in the income of unitholders. The remaining 30.16% reduced each unitholder's adjusted cost base for income tax purposes. A summary of cash distributions paid in 2003 and the implications for Canadian taxpayers is shown below.

<i>Record Date</i>	<i>Payment Date</i>	<i>Distribution*</i> (\$ per unit)	<i>Taxable Income</i> (\$ per unit)	<i>ACB Reduction</i> (\$ per unit)
Dec. 31, 2002	Jan. 15, 2003	\$ 0.60	\$ 0.4190	\$ 0.1810
February 28, 2003	March 15, 2003	\$ 0.22	\$ 0.1536	\$ 0.0664
March 31, 2003	April 15, 2003	\$ 0.28	\$ 0.1956	\$ 0.0844
April 30, 2003	May 15, 2003	\$ 0.28	\$ 0.1956	\$ 0.0844
May 31, 2003	June 15, 2003	\$ 0.23	\$ 0.1606	\$ 0.0694
June 30, 2003	July 15, 2003	\$ 0.23	\$ 0.1606	\$ 0.0694
July 31, 2003	August 15, 2003	\$ 0.23	\$ 0.1606	\$ 0.0694
August 31, 2003	September 15, 2003	\$ 0.23	\$ 0.1606	\$ 0.0694
September 30, 2003	October 15, 2003	\$ 0.23	\$ 0.1606	\$ 0.0694
October 31, 2003	November 15, 2003	\$ 0.23	\$ 0.1606	\$ 0.0694
November 30, 2003	December 15, 2003	\$ 0.23	\$ 0.1606	\$ 0.0694
Total		\$ 2.99	\$ 2.0880	\$ 0.9020

* Note: Distributions for income tax purposes are based on cash received during 2003 rather than accrual based income reported elsewhere in this report.

For US unitholders, 50.87% of distributions were taxable in 2003. Unitholders in both Canada and the US should consult tax advisors as to the proper treatment of Shiningbank distributions for income tax purposes.

ANNUAL FINANCIAL INFORMATION

<i>(000s except Trust Unit amounts)</i>	<i>2003</i>	<i>2002</i>	<i>2001</i>
Oil and natural gas sales	\$ 242,157	\$ 142,661	\$ 170,714
Net earnings	64,435	13,032	50,651
Per Trust Unit – basic	1.55	0.40	2.08
Per Trust Unit – diluted	1.52	0.39	2.08
Total assets	601,618	494,303	503,065
Total long term debt	121,691	115,283	122,459
Distributions	122,287	69,607	81,979
Per Trust Unit	2.85	2.16	3.40
Dividends to former Manager	–	517	819

Shiningbank's growth is driven by acquisitions. The main drivers behind year over year increases in assets, revenue and earnings were: the corporate acquisition of Ionic in 2001, a smaller property acquisition at Minehead in 2002 and the 2003 acquisition of the Ferrier/O'Chiese properties.

Shiningbank is primarily a natural gas producer – 74% of production. Weaker natural gas prices in 2002 offset the effect of additional volumes acquired, resulting in lower revenue and earnings. Gas prices rebounded in 2003 and are expected to remain strong in 2004.

QUARTERLY FINANCIAL INFORMATION

<i>(000s except for Trust Unit amounts)</i>	<i>March 31</i>	<i>June 30</i>	<i>September 30</i>	<i>December 31</i>
2003				
Oil and natural gas sales	\$ 59,074	\$ 64,212	\$ 61,690	\$ 57,181
Net earnings	19,783	23,850	15,796	5,006
Per Trust Unit – basic	0.55	0.57	0.36	0.11
– diluted	0.55	0.56	0.35	0.11
Distributions	30,886	30,330	30,442	30,629
Per Trust Unit	0.78	0.69	0.69	0.69
2002				
Oil and natural gas sales	\$ 29,823	\$ 36,804	\$ 33,918	\$ 42,116
Net earnings (loss)	2,982	7,061	5,061	(2,072)
Per Trust Unit – basic	0.10	0.22	0.15	(0.06)
– diluted	0.10	0.22	0.15	(0.06)
Distributions	14,559	17,897	17,234	19,917
Per Trust Unit	0.50	0.54	0.52	0.60

As with Shiningbank's annual results, quarterly fluctuations are primarily the result of changes in realized gas prices, which can be extremely volatile. Gas prices in 2003 peaked in the first quarter and then declined for most of the year. This effect offset production increases from the Ferrier/O'Chiese acquisition in the second quarter, reducing the quarter over quarter increases that might have been expected based on production volume growth. This is evident in revenue, earnings and distributions. Per unit earnings and long term debt were also affected by equity issues in the first and second quarters.

Gas prices in 2002 were relatively soft throughout the year as a result of a warm winter in 2001/2002. Prices did not firm up until late in 2002. Earnings in fourth quarter 2002 were affected by the costs of internalizing the management contract. Distributions were unaffected by this largely non-cash transaction and rose due to strengthening commodity prices in that quarter.

COSTS OF ACQUISITION AND DEVELOPMENT

During the year, Shiningbank spent a total of \$156.8 million on new properties in 10 transactions. The most significant acquisition was the first quarter purchase of properties at Ferrier/O'Chiese for \$133.7 million, after closing adjustments. Acquisitions during 2003 increased daily production by an average 3,309 boe/d. With the cumulative impact of 2003 acquisitions, daily production in the fourth quarter was up an average 4,469 boe/d.

The Fund disposed of non-core properties for \$5.8 million during the year, representing an estimated average of 117 boe/d of production for the year.

A total of \$22.9 million was spent on drilling and new facilities during 2003, compared with only \$11.9 million in the prior year. The substantial increase was due to funding of a low risk, successful development drilling program at Ferrier/O'Chiese. Of the year's total, \$6.9 million was spent in the fourth quarter compared with \$5.0 million in fourth quarter 2002.

NET ASSET VALUE

(000s)	Discount Factor	
	10%	12%
Present value of reserves		
Proved	\$ 448,019	\$ 420,834
Probable	98,130	85,303
Undeveloped lands	18,100	18,100
Working capital (deficit)	(16,938)	(16,938)
Total assets	547,311	507,299
Long term debt	(121,691)	(121,691)
Net asset value	\$ 425,620	\$ 385,608
Trust Units outstanding (000s)	44,343	44,343
Net asset value per Trust Unit at December 31, 2003	\$ 9.60	\$ 8.70

Note: The present value of reserves is calculated based on price forecasts prepared by Paddock Lindstrom & Associates Ltd. in its December 31, 2003 evaluation.

Liquidity and Capital Resources**LONG TERM DEBT**

The Corporation has a \$195 million revolving credit facility with a syndicate of four Canadian chartered banks of which \$121.7 million was drawn at December 31, 2003. The revolving period extends to April 28, 2004, at which time the facility reverts to a three-year term with principal repayments, if necessary, commencing July 28, 2004. The facility is secured by a \$300 million floating charge debenture on all assets of the Corporation. Borrowings under the facility bear interest at an annual rate ranging from the banks' prime rate to the banks' prime rate plus 0.95%, depending on the Corporation's total debt to cash flow ratio, or, at Shiningbank's option, the bankers' acceptance rate plus a stamping fee.

The Fund's governing documents restrict debt levels to 40% of the value of its properties, and debt service costs are not to exceed 30% of the projected annual cash flow. Neither of these limits was being approached at December 31, 2003.

UNITHOLDERS' EQUITY

On February 11, 2003, the Fund issued 3,841,000 new Trust Units at \$15.00 each for gross proceeds of \$57.6 million. On April 29, 2003, the Fund issued a further 6,497,500 new Trust Units at \$15.00 each for gross proceeds of \$97.5 million. In addition, a total of 810,978 units were issued during the year through the exercise of Exchangeable Shares, under the Fund's Distribution Reinvestment Program, and under the Trust Unit Rights Incentive Plan.

The Fund had 44,343,415 Trust Units outstanding at December 31, 2003.

As at December 31, 2003, 126,290 non-escrowed Exchangeable Shares and 555,678 escrowed Exchangeable Shares were outstanding. Exchangeable Shares held in escrow will be released over the next four years under the terms of two escrow agreements. Exchangeable shares are not eligible for distributions until they are exchanged for Trust Units at the discretion of the holder. The exchange rate was initially one Trust Unit for each Exchangeable Share. The exchange rate increases with each distribution by an amount equal to the per unit distribution divided by the 10-day weighted average trading price of the Trust Units preceding the record date for that distribution. As of December 31, 2003, the exchange rate was 1 to 1.18417.

On March 8, 2004, the Fund closed the issue of 8,800,000 Trust Units at a price of \$17.00 each for gross proceeds of \$149.6 million.

FUTURE GROWTH

Shiningbank's growth is based on its ability to raise debt and equity capital in Canadian financial markets. The Fund examines acquisition opportunities and selects those it believes to be accretive for such parameters as cash flows, distributions, net asset value, production and reserves.

Acquisitions are typically made using the Fund's credit facilities. Periodically, new Trust Units are issued, and the proceeds are used to pay down debt accumulated from previous acquisitions.

If the Canadian equity or debt markets were unable to satisfy Shiningbank's funding needs, it would impair the Fund's ability to continue to replace production and maintain distributions. The Fund has lines of credit held by four Canadian chartered banks, which provide sufficient debt capital to satisfy the Fund's ability to complete all but the largest acquisitions. However, the Fund's governing documents restrict debt levels to 40% of the value of its properties, and debt service costs are not to exceed 30% of the projected annual cash flow.

Financial Reporting

During 2003, there were numerous changes to financial reporting and regulatory requirements. The most important changes for Shiningbank are described below. Some of these standards were adopted in 2003 and others will be adopted in 2004.

STOCK-BASED COMPENSATION

In September 2003, the CICA amended section 3870 of its handbook – "Stock-based compensation and other stock-based payments." Effective January 1, 2004, companies are required to use the fair value to measure all stock-based payments and recognize compensation expense in their financial statements. The Fund elected to adopt these amendments in fourth quarter 2003 for all rights issued on or after January 1, 2003.

Previously, the Fund followed common practice in the sector and used the excess of the unit price over the exercise price at the date of the financial statement as a surrogate for fair value. If the Fund were to continue to use this method under the amended standard, the Fund could experience large fluctuations, even recoveries, in compensation expense over the next 10 years. Because of the highly volatile nature of distributions and unit trading prices, management believes amounts expensed and/or recovered under this calculation do not properly represent the benefit conveyed to rights holders during the vesting period, and could be confusing when reading the financial statements.

Management considered numerous methods of determining the fair value of rights granted and has chosen to use the Black-Scholes option-pricing model to determine fair value. The calculation of fair value requires management to make numerous assumptions, as outlined in note 6 to the financial statements. Readers are cautioned that the assumptions made are estimates of future events and actual results could differ materially from those estimated.

FULL COST ACCOUNTING GUIDELINE

In December 2003, the Fund adopted CICA Accounting Guideline 16, “Oil and gas accounting – full cost.” Under the new guideline, cash flows used in the ceiling test calculation are estimated using expected future product prices and costs. Future prices were obtained from third parties, adjusted for commodity differentials specific to the Fund, and then escalated based on factors in the Fund’s year-end independent reserves evaluation. At December 31, 2003, there was no impact under this calculation. There were no changes to net income, fixed assets or any other reported amounts as a result of adopting this guideline.

HEDGING RELATIONSHIPS

Effective for the Fund’s 2004 fiscal year, the new CICA Accounting Guideline 13, “Hedging relationships” requires that hedging relationships be identified, designated, documented and measured in order for the Fund to apply hedge accounting. The Fund was in compliance with this new standard at December 31, 2003, and all hedges will continue to be accounted for using hedge accounting.

ASSET RETIREMENT OBLIGATIONS

In March 2003, the CICA issued handbook section 3110, “Asset retirement obligations.” This requires the recognition and measurement of liabilities related to legal obligations to retire property, plant and equipment upon acquisition of the liability. The initial liability must be measured at fair value and subsequently adjusted for the accretion of discount and changes in the fair value. The asset retirement cost is capitalized and depleted into earnings over time. This section will be in effect for Shiningbank in 2004. The adoption of this standard at December 31, 2003 would have increased the asset retirement liability by approximately \$15 million, and added an undepleted asset retirement cost of approximately \$13 million to fixed assets.

Business Risks

Shiningbank is faced with a number of business risks that are inherent in the oil and gas business, and which can have a material impact on distributions to unitholders. To mitigate these risks, the Fund employs policies and procedures in its day-to-day operations and in its longer-term planning. These risk factors include, but are not limited to, the following influences:

MARKET RISKS

Commodity prices

The primary risk to cash flow and therefore, distributions, is fluctuations in oil and gas prices. With Shiningbank’s production weighted heavily to natural gas, changes in natural gas markets and pricing are the primary driver behind the level of distributions.

To mitigate price risk, the Fund actively manages the sales of its production to optimize pricing and volumes. The Fund has an active hedging program through which management attempts to minimize the effect of commodity price drops in the short run, while retaining exposure to upward price changes. This is accomplished by use of simple hedging instruments, primarily “costless collars” and fixed price swaps.

Under the Fund’s hedging policy, not more than 50% of production volumes can be hedged at any one time. Shiningbank’s hedging practices are not designed to have a material impact on the medium and long-term effects of commodity prices on distributions to unitholders. Unitholders remain exposed to price fluctuations over time. Hedging is employed only as a risk-management tool to stabilize distributions, and not for speculation.

Interest Rates

Shiningbank is exposed to changes in interest rates. Interest rates have less of an impact on distributions than changes in commodity prices. The Fund's governing documents restrict debt levels to 40% of the value of its properties, and debt service costs are not to exceed 30% of the projected annual cash flow.

The Fund has a line of credit that bears interest at current short-term market rates. In addition, \$10.0 million in debt has a fixed rate of 3.48%, plus applicable stamping fees, until October 2004 through an interest rate swap.

Currency Rates

Exposure to currency exchange risk arises from the fact that prices for oil and, to a lesser degree natural gas, are determined in international markets, usually in US dollars. As a result, the amount received by Shiningbank may be dependent on the strength of the Canadian dollar versus the US dollar.

Shiningbank has the ability to hedge its currency exposure to manage currency fluctuations. The Fund currently has no hedges of this type in place.

POLITICAL AND LEGAL RISKS

Shiningbank's activities are affected by the political and legal environment in which it operates. Some examples of these uncertainties include:

- *Changes in securities regulations which could affect the Fund's ability or cost structure related to raising additional equity or debt capital;*
- *Changes in environmental regulations which could increase the cost of operating oil and gas producing properties;*
- *Changes in income tax laws which could affect either tax costs to the Fund or to its unitholders;*
- *Changes in provincial Crown royalty regulation and compliance; and,*
- *Changes in law that affect the price or ownership of oil and gas reserves and production.*

Unitholders' Liability

In the investment community, there has been increasing discussion about the lack of statutory protection for unitholders in mutual fund trusts. Under Canadian law, a shareholder's liability in a corporation is limited to their investment in the corporation. However, there is no limit set out by statute for individual holders of units in trusts. Unitholders in Shiningbank are shielded from liability through the structure of the Fund, which uses corporate entities to hold all producing assets and to employ staff. In addition, the Fund has substantial insurance coverage at all times to protect against exposure to liability.

The industry is now lobbying provincial governments to extend statutory limited liability to unitholders of all publicly-held trusts. The Ontario government has proposed such legislation. Shiningbank expects that all provinces will adopt similar legislation in the near future, perhaps in 2004. Nevertheless, it is management's view that this exposure to unitholders is extremely small.

OPERATING RISKS

Field Operations

Oil and gas production activities carry a number of inherent risks including production risks related to the ability to produce and process crude oil and natural gas from existing wells; the ability to develop or acquire sufficient quantities of crude oil and natural gas to replace production and maintain reserves; risks of environmental damage; and risks to the safety of its employees, contractors and the public.

To mitigate these risks, the Fund maintains financial flexibility to ensure its ability to operate efficiently in the field. The Fund employs skilled personnel, both in the field and in its head office, and ensures that they are equipped with efficient and effective tools and training. Shiningbank's strategy of operating a significant portion of its production provides greater control over operational factors, including ensuring properties are operated in accordance with its policy to minimize impacts on the environment.

Insurance coverage is maintained in order to minimize the impact of events that might cause substantial financial damage.

Reserve Replacement

As oil and gas reserves are produced, they naturally deplete over time. Shiningbank's ability to replace production depends on acquiring new reserves and developing existing reserves. Acquisition of oil and gas assets depends on the availability of economically desirable opportunities and on management's assessment of the value of the assets.

To mitigate these risks, the Fund subjects all potential prospects to stringent investment criteria, due diligence and review. All acquisitions over \$10 million require Board of Directors' review and approval.

Forward-Looking Statements

This discussion and analysis contains forward-looking statements relating to future events. In some cases, forward-looking statements can be identified by such words as "may," "expects" or similar expressions. These statements represent management's best speculations, but should not have undue reliance placed on them as they are derived from numerous assumptions. These assumptions are subject to known and unknown risks and uncertainties, including the numerous risks discussed above. Readers are cautioned that events or circumstances could cause results to differ from those predicted.

Financial Information



38	Management's Report
39	Auditors' Report
40	Consolidated Financial Statements
43	Notes to Consolidated Financial Statements
52	Five-Year Financial and Operating Review
54	Unitholders' Information
56	Corporate Information

Management's Report

Management is responsible for the integrity and objectivity of the information contained in this annual report and for the consistency between the financial statements and other financial operating data contained elsewhere in the report. The accompanying financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada using estimates and careful judgement, particularly in those circumstances where transactions affecting a current period are dependent upon future events. The accompanying financial statements have been prepared using policies and procedures established by management and reflect fairly the Fund's financial position, results of operations and cash flow, within reasonable limits of materiality and within the framework of the accounting policies as outlined in the notes to the financial statements.

Management has established and maintained a system of internal control which is designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and the financial information is reliable and accurate.

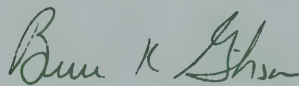
The financial statements have been examined by external auditors. Their examination provides an independent view as to management's discharge of its responsibilities insofar as they relate to the fairness of reported operating results and financial condition of the Fund.

The Audit Committee of the Board of Directors has reviewed in detail the financial statements with management and the external auditors. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.



David M. Fitzpatrick

President & Chief Executive Officer



Bruce K. Gibson

*Vice President,
Finance & Chief Financial Officer*

Auditors' Report

To the Unitholders of Shiningbank Energy Income Fund

We have audited the consolidated balance sheets of Shiningbank Energy Income Fund as at December 31, 2003 and 2002 and the consolidated statements of earnings and unitholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.



*Chartered Accountants
Calgary, Canada*

March 11, 2004

Consolidated Balance Sheets

December 31 (\$ thousands)	2003	2002
ASSETS		
Current assets		
Accounts receivable	\$ 31,587	\$ 23,637
Prepaid expenses	2,630	2,878
	34,217	26,515
Fixed assets (note 4)		
Petroleum and natural gas properties and equipment	805,633	631,204
Accumulated depreciation and depletion	(240,482)	(165,668)
	565,151	465,536
Other assets	2,250	2,252
	\$ 601,618	\$ 494,303
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	\$ 30,727	\$ 20,985
Trust Unit distribution payable	20,428	19,916
	51,155	40,901
Long term debt (note 5)	121,691	115,283
Future income taxes (note 7)	51,336	63,340
Provision for future site restoration	11,195	8,347
Unitholders' equity		
Trust Units (note 6)	550,267	391,970
Exchangeable Shares (note 6)	5,267	6,475
Contributed surplus (note 6)	572	—
Accumulated earnings	171,737	107,302
Accumulated Trust Unit distributions	(361,602)	(239,315)
	366,241	266,432
	\$ 601,618	\$ 494,303

See accompanying notes to the consolidated financial statements

Approved on behalf of Shiningbank Energy Income Fund by Shiningbank Energy Ltd.



Director



Director

Consolidated Statements of Earnings and Unitholders' Equity

<i>For the years ended December 31 (\$ thousands, except per Trust Unit amounts)</i>	<i>2003</i>	<i>2002</i>
Revenues		
Oil and natural gas sales	\$ 242,157	\$ 142,661
Royalties	(53,628)	(26,470)
	188,529	116,191
Expenses		
Operating	40,536	31,583
General and administrative	4,649	4,143
Management fees	—	1,939
Interest on long term debt	6,103	5,109
Depreciation, depletion and amortization	75,027	60,034
Provision for future site restoration	3,066	2,862
Capital and large corporation taxes (note 7)	595	665
Trust unit incentive compensation (note 6)	572	—
Internalization of management contract (note 10)	5,989	10,984
	136,537	117,319
Earnings (loss) before income taxes	51,992	(1,128)
Future income tax recovery (note 7)	(12,443)	(14,160)
Net earnings	\$ 64,435	\$ 13,032
Unitholders' equity, beginning of year	266,432	262,325
Issue of Trust Units	158,297	54,724
Exchangeable Shares, net (note 6)	(1,208)	6,475
Contributed surplus (note 6)	572	—
Trust Unit distributions	(122,287)	(69,607)
Dividends to Manager	—	(517)
Unitholders' equity, end of year	\$ 366,241	\$ 266,432
Net earnings per Trust Unit (note 6)		
Basic	\$ 1.55	\$ 0.40
Diluted	\$ 1.52	\$ 0.39

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

<i>For the years ended December 31 (\$ thousands, except per Trust Unit amounts)</i>	<i>2003</i>	<i>2002</i>
Operating activities		
Net earnings	\$ 64,435	\$ 13,032
Items not requiring cash		
Depreciation, depletion and amortization	75,027	60,034
Internalization of management contract	5,381	6,475
Provision for future site restoration	3,066	2,862
Trust unit incentive compensation	572	–
Future income tax recovery	(12,443)	(14,160)
Cash flow before change in non-cash working capital	136,038	68,243
Site restoration costs	(218)	(385)
Changes in non-cash working capital	1,514	478
	137,334	68,336
Financing activities		
Increase (decrease) in long term debt	6,408	(7,176)
Distributions to unitholders	(122,287)	(69,607)
Issue of Trust Units	151,708	54,724
Dividends paid	–	(517)
	35,829	(22,576)
Changes in non-cash working capital	512	5,357
	36,341	(17,219)
Total cash provided	\$ 173,675	\$ 51,117
Investing activities		
Property acquisitions	\$ (156,829)	\$ (49,595)
Deposits on future property acquisitions	–	(1,682)
Capital expenditures	(22,931)	(11,867)
Long term investments	(211)	(655)
Proceeds on sale of fixed assets	5,770	11,470
	(174,201)	(52,329)
Changes in non-cash working capital	526	1,212
Total cash used	\$ 173,675	\$ 51,117
Cash taxes paid	\$ 625	\$ 748
Cash interest paid	\$ 6,077	\$ 5,103

See accompanying notes to the consolidated financial statements

Notes to Consolidated Financial Statements

For the years ended December 31, 2003 and 2002 (\$ thousands, except Trust Units and per Trust Unit amounts)

1. ORGANIZATION

Shiningbank Energy Income Fund (the "Fund") is an unincorporated open-end investment trust formed under the laws of the Province of Alberta pursuant to a trust indenture dated May 16, 1996 and subsequently amended. Operations commenced on July 1, 1996. The beneficiaries of the Fund are the holders (the "Unitholders") of trust units (the "Trust Units").

Effective October 9, 2002, the Fund effected an internalization of its management by acquiring, through its wholly-owned subsidiary Shiningbank Holdings Corporation ("SHC"), all of the shares of Shiningbank Energy Management Inc., (the "Former Manager"). Subsequently the Former Manager and Shiningbank Energy Ltd. (the "Corporation") were amalgamated, continuing as Shiningbank Energy Ltd. (see note 10).

The trust indenture provides that 300,000,000 Trust Units may be issued. Each Trust Unit represents an equal fractional beneficial interest in any distributions from the Fund and in the net assets of the Fund on termination or winding up of the Fund. All Trust Units rank among themselves equally and rateably without discrimination, preference or priority. The trust indenture provides that Trust Units are redeemable at any time on demand by the Unitholders at amounts as determined by a market price formula. The total amount payable by the Fund in respect of all Trust Units tendered for redemption, however, may not exceed \$100,000 in any calendar month.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management using Canadian generally accepted accounting principles. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion, depreciation and amortization of the petroleum and natural gas properties, deferred charges, and for site reclamation and abandonment are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

(a) Principles of consolidation

These consolidated financial statements include the accounts of the Fund, SHC and the Corporation.

(b) Fixed assets

The Fund follows the full cost method of accounting for petroleum and natural gas properties under which all acquisition and development costs are capitalized. Such costs include land acquisition, geological, geophysical and drilling costs for productive and non-productive wells and directly related overhead charges. Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs. Gains or losses upon disposition of such properties are not recognized unless the disposition would alter the depletion and depreciation rate by 20% or more.

The costs of fixed assets, plus a provision for future development costs of proved undeveloped reserves, are depleted and depreciated using the unit-of-production method based on estimated total proved reserves volumes, before royalties, as determined by independent engineers. Proved reserves are converted to a common unit of measure on the basis of their approximate relative energy content. Other miscellaneous assets are depreciated on a declining balance basis at 20% per annum.

Oil and gas assets are evaluated annually to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre. The carrying amounts are assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is in excess, and is therefore assessed as not recoverable, an impairment loss would be recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate (see note 4).

(c) Future site restoration costs

Estimated future site restoration and abandonment costs are provided for using the unit-of-production method based on estimated total proved reserves volumes. Costs are estimated by the Fund based on current regulations, costs, technology and industry standards. Actual site restoration and abandonment costs are charged against the liability as incurred.

(d) Income taxes

The Fund is a taxable trust under the Income Tax Act (Canada). Any taxable income is allocated to the Unitholders and therefore no provision for income taxes relating to the Fund is included in these financial statements.

The Corporation and SHC follow the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

The Corporation and SHC are taxable Canadian corporations and are liable for tax on income that they retain. The Corporation is also subject to capital taxes in jurisdictions where such taxes apply and these taxes are deducted from distributions to Unitholders.

(e) Financial instruments

Financial instruments of the Corporation consist mainly of accounts receivable, accounts payable and accrued liabilities, and long term debt. The carrying value of these items approximates their fair value at December 31, 2003. The Corporation also from time to time employs financial instruments to manage exposures related to interest rates, Canada/US exchange rates and commodity prices. These instruments are not used for speculative trading purposes.

(f) Trust Unit incentive compensation plan

The Fund has a Trust Unit Rights Incentive Plan that is described in note 6. When Trust Unit rights are issued, Trust Unit incentive compensation is deferred and recognized into income over the vesting period of the rights, with a corresponding increase to contributed surplus. Consideration paid by employees and directors of the Corporation on the exercise of Trust Unit rights under the Fund's Trust Unit Rights Incentive Plan is recorded in Trust Units upon receipt, along with the amount of non-cash Trust Unit incentive compensation expense recognized in contributed surplus.

(g) Joint ventures

Substantially all of the Fund's petroleum and natural gas activities are conducted jointly with others and, accordingly, these financial statements reflect only the Fund's proportionate interest in such activities.

(h) Per Trust Unit amounts

Basic earnings per Trust Unit is computed by dividing net earnings by the weighted average number of Trust Units outstanding for the year. Diluted net earnings per Trust Unit amounts reflect the potential dilution that could occur if securities or other contracts to issue Trust Units were exercised or converted to Trust Units.

(i) Revenue recognition

Revenue from the sale of oil and natural gas is recognized when the product is delivered.

(j) Comparative figures

Comparative figures have been reclassified to conform to current year presentation.

3. CHANGE IN ACCOUNTING POLICIES

(a) Full cost accounting guideline

In December 2003, the Fund adopted AcG-16 "Oil and Gas Accounting – Full Cost", the new guideline issued by the Canadian Institute of Chartered Accountants ("CICA"). Under the new guideline, cash flows used in the ceiling test calculation are estimated using expected future product prices and costs. Prior to adopting this new standard, constant dollar pricing was used to test impairment. There were no changes to net income, fixed assets or any other reported amounts in the financial statements as a result of adopting this guideline.

(b) Trust Unit incentive compensation plan

Effective January 1, 2003, the Fund elected to prospectively adopt the amendments to the CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments." Under the amended standard, Trust Unit incentive compensation expense must be recognized based on the fair value of rights granted. Shiningbank used a Black-Scholes option-pricing model to determine the fair value at the date of grant.

4. FIXED ASSETS

(a) Fixed asset additions

During 2003, the Fund acquired additional petroleum and natural gas properties in the amount of \$156,829,000 (2002 – \$49,595,000) that have been accounted for as purchases.

(b) Ceiling test

The Fund performed a ceiling test calculation at December 31, 2003 to assess the recoverable value of fixed assets. Future prices were obtained from third parties, adjusted for commodity differentials specific to the Fund, and then escalated based on factors in the Fund's year-end independent reserves evaluation. The following table summarized the benchmark prices used in the ceiling test calculation. Based on these assumptions, the undiscounted value of future net revenues from proved reserves exceeded the carrying value of the Fund's fixed assets at December 31, 2003.

Year	Oil		Gas	
	WTI US\$/bbl	Edmonton Light C\$/bbl	AECO C\$/mmbtu	Alberta Reference C\$/mmbtu
2004	29.00	37.61	6.00	5.70
2005	26.50	34.25	5.31	5.07
2006	25.50	32.90	4.83	4.64
2007	25.00	32.21	4.87	4.68
2008	25.50	32.85	4.92	4.73
2009 – 2012	+ 2%/annum	+ 2%/annum	+ 1%/annum	+ 1%/annum
Thereafter	+ 2%/annum	+ 2%/annum	+ 2%/annum	+ 2%/annum

5. LONG TERM DEBT

The Corporation has a \$195 million revolving credit facility with a syndicate of four Canadian chartered banks of which \$121.7 million was drawn at December 31, 2003 (2002 – \$115.3 million). The revolving period extends to April 28, 2004, at which time the facility reverts to a three year term with principal repayments, if necessary, commencing July 28, 2004. The facility is secured by a \$300 million floating charge debenture on all assets of the Corporation. Borrowings under the facility bear interest at an annual rate ranging from the banks' prime rate to the banks' prime rate plus 0.95%, depending on the Corporation's total debt to cash flow ratio, or, at Shiningbank's option, the bankers' acceptance rate plus a stamping fee.

6. TRUST UNITS

(a) Authorized

300,000,000 Trust Units

(b) Issued

	2003		2002	
	Number	Amount	Number	Amount
Balance, beginning of year	33,193,937	\$ 391,970	29,117,937	\$ 337,246
Issued for cash	10,652,661	159,925	4,076,000	57,844
Commissions and issue costs	—	(8,216)	—	(3,120)
Issued on conversion of Exchangeable Shares	496,817	6,588	—	—
Balance, end of year	44,343,415	\$ 550,267	33,193,937	\$ 391,970

(c) Exchangeable Shares

On October 9, 2002, SHC issued 1,136,614 Exchangeable Shares in connection with the management internalization transaction. The Exchangeable Shares are exchangeable, at the option of the holder, into Trust Units for no additional consideration. As at December 31, 2003, 555,678 (2002 – 757,742) Exchangeable Shares were held in escrow to be released over periods of up to four years under the terms of two escrow agreements. The number of Trust Units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted by the distributions paid to unitholders divided by the 10 day weighted average unit price preceding the record date. The Exchangeable Shares are not eligible for distributions.

	2003		2002	
	Number	Amount	Number	Amount
Balance, beginning of year	378,872	\$ 6,475	—	\$ —
Non-escrowed issued to Former Manager shareholders	—	—	378,872	6,475
Released from escrow	202,064	—	—	—
Conversion of Exchangeable Shares	(454,646)	(6,589)	—	—
Amortization of deferred portion	—	5,381	—	—
Balance, end of year	126,290	\$ 5,267	378,872	\$ 6,475
Exchangeable ratio, end of year	1.18417		1.00000	
Trust Units issuable upon conversion of non-escrowed shares	149,549		378,872	
Trust Units issuable upon conversion of escrowed shares	658,016		757,742	
Total Trust Units issuable upon conversion	807,565		1,136,614	

(d) Trust Unit Rights Incentive Plan

Under Shiningbank's Trust Unit Rights Incentive Plan the initial exercise price of rights granted may not be less than the current market price of the Trust Units as of the date of grant and the maximum term of each right is not to exceed 10 years. The exercise price of the rights is to be adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceed 2.5% percent (10% annually) of the Fund's consolidated net book value of fixed assets. A total of 2,710,483 Trust Units have been reserved for issuance under the plan. At December 31, 2003, there were 1,460,067 (2002 – 1,059,000) rights outstanding, of which 583,401 (2002 – 452,333) were exercisable at a weighted average exercise price of \$14.20 (2002 – \$15.27).

	2003		2002	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Balance, beginning of year	1,059,000	\$ 15.00	625,000	\$ 16.92
Granted	525,000	15.24	485,000	13.97
Exercised	(123,933)	13.44	(51,000)	13.51
Balance before reduction of exercise price	1,460,067	\$ 15.22	1,059,000	\$ 15.71
Reduction of exercise price		(1.29)		(0.71)
Balance, end of period	1,460,067	\$ 13.93	1,059,000	\$ 15.00

Shiningbank recorded Trust Unit incentive compensation expense and contributed surplus of \$572,000 on rights granted and vesting during 2003. The amount of compensation expense was reduced for rights granted during the year but cancelled prior to vesting.

The fair value of rights issued during the year was estimated using a Black-Scholes option-pricing model with the following assumptions: risk-free interest rates ranging from 4.15 to 4.76%, volatility of 60%, life of 10 years, and a dividend yield rate of 10% representing the difference between the anticipated distribution and the anticipated drop in the strike price. Users are cautioned that the assumptions made are estimates of future events and actual results could differ materially from those estimated.

For rights issued in 2002, Shiningbank has elected to disclose the pro forma effect as if the amended accounting standard had been adopted January 1, 2002. For the years ended December 31, 2003 and 2002, Shiningbank's net income would have decreased by \$508,000 (\$0.01 per basic and diluted Trust Unit in 2003. \$0.02 per basic and \$0.03 diluted Trust Unit in 2002) due to additional Trust Unit incentive compensation expense related to rights granted on January 1, 2002.

(e) Distribution Reinvestment Program

The Distribution Reinvestment Program ("DRIP") entitles eligible Unitholders to purchase additional Trust Units by re-investing their cash distributions or by making additional optional cash payments of up to a maximum of \$3,000 per quarter for the purchase of additional Trust Units. Trust units are acquired on the open market at the prevailing market price or issued from treasury at the average market price over the last 10 days of trading. During 2003, 179,488 Trust Units were issued from treasury (2002 – nil) under the DRIP for proceeds of \$3.0 million.

(f) Per Trust Unit amounts

For the year ended December 31, 2003, the weighted average number of Trust Units and non-escrowed Exchangeable Shares outstanding was 41,594,854 (2002 – 31,677,071). In computing diluted net earnings per Trust Unit, the dilutive effect of unit rights and escrowed Exchangeable Shares, added 772,760 Trust Units (2002 – 305,555) to the weighted average number of Trust Units outstanding.

For the year ended December 31, 2002, diluted net earnings per Trust Unit was calculated using the if-converted method for the effect of the escrowed Exchangeable Shares. Net earnings available to current and potential unitholders were decreased by the deferred portion of the internalization of the management contract for purposes of the calculation. During the year, the Fund determined that it would be more appropriate to use the treasury stock method to calculate the effect of the escrowed Exchangeable Shares. Under the treasury stock method, the deferred portion of the internalization of the management contract is treated as funds from conversion and considered to have been used to repurchase units at the weighted average market price. For the year ended December 31, 2002, the diluted net earnings per Trust Unit would have been \$0.39, as compared to the \$0.08 previously reported.

7. INCOME TAXES

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Corporation's and SHC's earnings before income taxes. This difference results from the following items:

	2003	2002
Taxable loss of the Corporation and SHC	\$ (17,400)	\$ (43,700)
Combined federal and provincial tax rate	40.60%	42.12%
Computed income tax recovery	(7,100)	(18,400)
Increase (decrease) in income taxes resulting from:		
Non-deductible Crown charges	1,800	100
Resource allowance	(1,900)	(300)
Change in tax rate	(7,700)	(860)
Other	57	700
Internalization of management contract	2,400	4,600
Future income tax recovery	(12,443)	(14,160)
Capital and large corporation taxes	595	665
Income and capital taxes	\$ (11,848)	\$ (13,495)

The components of the Corporation's and SHC's future income tax liability at December 31 are as follows:

	2003	2002
Future income taxes:		
Oil and natural gas properties	\$ 59,999	\$ 73,020
Provision for site restoration	(3,864)	(2,630)
Non-capital losses	(3,935)	(6,280)
Other	(864)	(770)
	\$ 51,336	\$ 63,340

8. RELATED PARTY TRANSACTIONS

Prior to the internalization transaction on October 9, 2002, the Former Manager provided services to the Fund and the Corporation pursuant to a management agreement. With the termination of this agreement, all such payments ceased. In 2002, the Fund, through the Corporation, paid the Former Manager \$7.1 million for management fees, recovery of general and administrative and financing expenses, including \$721,000 in respect of acquisition fees which were capitalized.

9. FINANCIAL INSTRUMENTS

As at December 31, 2003, there are no significant differences between the carrying amounts and the fair value of accounts receivable, accounts payable and accrued liabilities, and long-term debt. The Corporation is exposed to interest rate variance on the long term debt disclosed in the balance sheet. Gains and losses on exchange rate and commodity price hedges are included in revenues upon the sale of related production provided there is reasonable assurance that the hedge is and will continue to be effective.

At December 31, 2003, Shiningbank held certain oil and natural gas hedge contracts, the terms of which are listed in the following table. The estimated market value at December 31, 2003, had the contracts been settled at that time, would have been a loss of \$821,394.

<i>Period</i>	<i>Commodity</i>	<i>Volume</i>	<i>Price</i>
January 1, 2004 – December 31, 2004	Gas	11,000 GJ/d	\$6.11/GJ
January 1, 2004 – March 31, 2004	Gas	5,000 GJ/d	\$6.00/GJ floor \$8.55/GJ ceiling
January 1, 2004 – September 30, 2004	Oil	500 bbl/d	US\$25.00/bbl floor US\$30.00/bbl ceiling
October 1, 2004 – December 31, 2004	Oil	500 bbl/d	US\$25.00/bbl floor US\$30.00/bbl ceiling

Subsequent to December 31, 2003, the Corporation entered into five additional hedging contracts.

<i>Period</i>	<i>Commodity</i>	<i>Volume</i>	<i>Price</i>
April 1, 2004 – October 31, 2004	Gas	5,000 GJ/d	\$5.25/GJ floor \$6.67/GJ ceiling
April 1, 2004 – October 31, 2004	Gas	5,000 GJ/d	\$5.45/GJ floor \$6.32/GJ ceiling
April 1, 2004 – March 31, 2005	Gas	5,000 GJ/d	\$5.91/GJ
April 1, 2005 – December 31, 2005	Gas	5,000 GJ/d	\$5.00/GJ floor \$6.39/GJ ceiling
March 1, 2004 – December 31, 2004	Oil	500 bbl/d	US\$31.87/bbl

As at December 31, 2003, the Corporation held an interest rate swap for \$10.0 million at an interest rate of 3.48% expiring October 30, 2004. The estimated market value at December 31, 2003, had the contract been settled at that time, would have been a loss of \$85,800.

10. INTERNALIZATION OF MANAGEMENT CONTRACT

Effective October 9, 2002, the Fund acquired all of the outstanding shares of Shiningbank Energy Management Inc., the Former Manager of the Fund. Total consideration for the transaction consisted of a cash payment of \$2.91 million plus 1,136,614 Exchangeable Shares. Total consideration was reduced by \$1.8 million to provide for performance/retention bonuses to be paid to employees over the next five years. During 2003, \$582,750 (2002 – \$400,000) of this bonus pool was paid out in cash.

Total consideration:	
Cash	\$ 2,910
Exchangeable Shares issued	16,490
Costs associated with the transaction	1,195
Total purchase price	\$ 20,595

Prior to the acquisition, the Fund paid fees to the Former Manager of 3.25% of net operating income, a fees of 1.5% on the purchase price of acquisitions and a quarterly scheduled dividend in accordance with the terms of the management agreement. The acquisition resulted in the elimination of all fees and dividends under the management contract.

Exchangeable Shares in the amount of \$10.0 million were originally subject to escrow provisions and are being deferred and amortized into income as internalization of management contract expense over the specific vesting periods through 2007. For the year ending December 31, 2003, \$5,380,600 (2002 – \$978,200) has been recorded as expense representing the amortization of these escrowed Exchangeable Shares.

11. SUBSEQUENT EVENTS

(a) Acquisition of Birchill Resources Limited

Subsequent to December 31, 2003, the Fund entered into an agreement to acquire all of the outstanding shares of Birchill Resources Limited ("Birchill"), for \$175 million, subject to certain adjustments. The effective date of the acquisition is January 1, 2004 and the transaction closed on March 8, 2004.

Cash consideration	\$ 169,660
Related fees and expenses	400
Cost of acquisition	\$ 170,060
Working capital deficiency	\$ (10,069)
Working capital adjustment to acquisition date	4,729
Future income taxes	(59,000)
Future site restoration costs	(2,767)
Petroleum and natural gas properties and equipment	222,204
Goodwill	14,963
Total consideration	\$ 170,060

(b) Equity offering

In conjunction with the Birchill acquisition, the Fund issued 8,800,000 subscription receipts at \$17.00 each for gross proceeds of \$149,600,000 effective March 8, 2004. On March 8, 2004, at the time of the close of the Birchill acquisition, the subscription receipts were converted to Trust Units on a 1 for 1 basis.

Five-Year Financial and Operating Review

FINANCIAL

(\$000s, except Trust Unit amounts)	2003	2002	2001	2000	1999
Oil and natural gas sales	\$ 242,157	\$ 142,661	\$ 170,714	\$ 104,772	\$ 44,129
Royalties	(53,628)	(26,470)	(38,857)	(21,565)	(7,909)
Operating expenses	(40,536)	(31,583)	(28,257)	(14,959)	(11,446)
Operating netback	147,993	84,608	103,600	68,248	24,774
General and administrative	4,649	4,143	3,788	2,577	2,102
Management fees	—	1,939	3,500	2,134	849
Interest	6,103	5,109	5,675	3,020	2,175
Internalization of management contract	608	4,509	—	—	—
Other	595	665	384	477	135
Cash flow before change in non-cash working capital	136,038	68,243	90,253	60,040	19,513
Depreciation, depletion and amortization	75,027	60,034	47,032	19,825	13,781
Provision for site restoration	3,066	2,862	2,470	1,351	1,069
Internalization of management contract	5,381	6,475	—	—	—
Trust unit incentive compensation	572	—	—	—	—
Future income taxes	(12,443)	(14,160)	(9,900)	1,100	—
Net earnings	\$ 64,435	\$ 13,032	\$ 50,651	\$ 37,764	\$ 4,663
Cash flow before change in non-cash working capital	\$ 136,038	\$ 68,243	\$ 90,253	\$ 60,040	\$ 19,513
Capital expenditures and site restoration costs	(23,149)	(12,252)	(4,819)	(5,838)	(2,129)
Internalization of management contract	608	4,509	—	—	—
Working capital adjustments	8,790	9,107	(3,455)	(11,792)	16
Distributable income	\$ 122,287	\$ 69,607	\$ 81,979	\$ 42,410	\$ 17,400
Distributions per Trust Unit	\$ 2.85	\$ 2.16	\$ 3.40	\$ 2.76	\$ 1.60
Long term debt	121,691	115,283	122,459	57,381	35,519
Acquisition and development costs	179,760	63,144	323,204	116,362	28,283
Unitholders' equity	366,241	266,432	262,325	118,231	68,935
Total assets	601,618	494,303	503,065	232,773	118,242
Trust Units outstanding at year end	44,343	33,194	29,118	16,829	11,792
Average Trust Units outstanding during year	41,595	31,677	24,005	14,167	10,660
Trading history					
High	\$ 18.99	\$ 15.95	\$ 18.70	\$ 18.50	\$ 11.40
Low	\$ 14.80	\$ 10.00	\$ 11.85	\$ 9.90	\$ 9.45
Close	\$ 18.64	\$ 15.15	\$ 13.97	\$ 17.00	\$ 10.65
Volume (millions of units)	37.3	25.0	27.1	9.0	5.1

OPERATING

	2003	2002	2001	2000	1999
Production					
Oil (bbl/d)	2,023	2,054	2,013	1,402	1,298
Natural gas (mmcf/d)	74.9	64.2	61.6	35.7	27.5
NGL (bbl/d)	2,252	1,454	1,288	962	697
Boe (bbl/d) (6:1)	16,759	14,214	13,564	8,312	6,572
Natural gas percentage of total production	74%	75%	76%	72%	70%
Average sales price (after hedging)					
Oil (\$/bbl)	\$ 37.95	\$ 36.31	\$ 35.67	\$ 41.95	\$ 25.85
Natural gas (\$/mcf)	\$ 6.82	\$ 4.32	\$ 5.80	\$ 5.45	\$ 2.68
NGL (\$/bbl)	\$ 33.65	\$ 26.59	\$ 29.59	\$ 34.52	\$ 19.54
Boe (\$/boe) (6:1)	\$ 39.59	\$ 27.50	\$ 34.48	\$ 34.44	\$ 18.40
Proved plus probable (established) reserves					
Oil and NGL (mbbls)	15,236	11,893	12,044	9,361	7,882
Natural gas (bcf)	253.0	210.0	210.8	151.3	85.4
Boe (\$/boe) (6:1)	57,395	46,890	47,171	34,583	22,116

Unitholders' Information

DISTRIBUTION SCHEDULE

Distributions are paid on the 15th of each month. We announce the amount that will be paid per unit near the middle of the previous month. Only unitholders of record on the last day of the month, which is our “record date”, receive distributions. For example, you must have been a unitholder on January 31 to receive the distributions on February 15. If you were just buying new units, you would have had to purchase them at least three days before the end of the month, known as the “ex-distribution date”. We announce the ex-distribution date with each distribution announcement.

Distributions are paid in Canadian funds directly to registered unitholders, or to brokers holding the units of non-registered unitholders.

WHAT ARE THE TAX BENEFITS?

Canada

For Canadian income tax purposes, only a portion of each distribution is considered income, while the remainder is a return of capital. See page 30 for a full breakdown of the taxable portion of distributions for 2003.

Residents of the United States

US residents may also be able to treat a portion of their distributions as a return of capital. This year, 50.87% was considered taxable and 49.13% a return of capital. US residents may also be able to treat the distributions as “qualified dividends” to receive a lower tax rate. This information however is not specific to individual unitholders and each person should consult their tax advisor.

Is there a withholding tax?

Non-residents are subject to Canadian government withholding tax, which is deducted from each distribution. The withholding rate is typically 15% for residents of the US and most European and Commonwealth countries.

HOW TO CALCULATE YOUR TOTAL RETURN

Total return takes into account how much you have received in cash distributions, and any increase (or decrease) in the unit price. There is a simple formula for calculating annual return. For 2003:

Subtract the unit price at year-end 2002 from the year-end price in 2003. Add 2003 distributions. Then divide by the 2002 year-end price.

Unit price as at:	
December 31, 2003	\$ 18.64
December 31, 2002	15.15
	\$ 3.49
Add 2003 distributions	2.85
	\$ 6.34
Divide by \$15.15	42%

DISTRIBUTION HISTORY

<i>Cash Distributions (\$)</i>	<i>Q1</i>	<i>Q2</i>	<i>Q3</i>	<i>Q4</i>	<i>Annual Total</i>
1996 (Formed mid-1996)	—	—	0.407	0.420	0.827
1997	0.40	0.40	0.40	0.40	1.60
1998	0.37	0.35	0.35	0.36	1.43
1999	0.35	0.38	0.42	0.45	1.60
2000	0.50	0.58	0.68	1.00	2.76
2001	1.10	1.10	0.70	0.50	3.40
2002	0.50	0.54	0.52	0.60	2.16
2003*	0.78	0.69	0.69	0.69	2.85
Total since inception					16.627

*Distributions were changed from quarterly to monthly. These are the sum of monthly distributions.

DISTRIBUTION REINVESTMENT PLAN

Our Distribution Reinvestment Plan allows you to automatically purchase units with monthly cash distributions in your investment account. For more information contact your broker or Computershare:

Computershare

Toll-free: 1-800-564-6253

WHO TO CONTACT

Questions about your units?

If you have administrative questions related to your units, please contact our trustee:

Computershare

Toll-free: 1-800-564-6253

Regular mailings

If you wish to be placed on our mailing list to receive annual and quarterly reports, please contact Shiningbank or send in the card enclosed:

Shiningbank Energy Income Fund

Toll-free: 1-866-268-7477

Wondering about Shiningbank?

If you have questions about our operations or new developments at the Fund, please contact us directly:

Shiningbank Energy Income Fund

Toll-free: 1-866-268-7477 or

Email: irinfo@shiningbank.com

Looking for press releases?

Check our website:

www.shiningbank.com

Corporate Information

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Fax: (403) 268-7499
Toll free: (866) 268-7477
E-mail: irinfo@shiningbank.com
Website: www.shiningbank.com

TRUSTEE

Computershare Trust Company of Canada
Calgary, Alberta

AUDITORS

KPMG LLP
Calgary, Alberta

ENGINEERING CONSULTANTS

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta

LEGAL COUNSEL

Gowling Lafleur Henderson LLP
Calgary, Alberta

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Symbol: SHN.UN

BOARD OF DIRECTORS

Arne R. Nielsen
Chairman

David M. Fitzpatrick
*President and
Chief Executive Officer*

D. Grant Gunderson
Director

Edward W. Best
Director

Warren D. Steckley
Director

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*President and
Chief Executive Officer*

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*Vice President,
Finance and
Chief Financial Officer*

Gregory D. Moore
Vice President, Operations

Terry P. Prokopy
Vice President, Land

Richard W. Clark
Corporate Secretary

Alan G. Glessing
Controller

NOTICE OF MEETING

The Special and Annual General Meeting of the unitholders of Shiningbank Energy Income Fund and the Annual General Meeting of Shiningbank Energy Ltd. will be held on Wednesday May 12, 2004 beginning at 3:00 p.m. (local time) at the Calgary Petroleum Club 319 – 5th Avenue S.W., Calgary, Alberta, Canada. Unitholders are encouraged to attend, and those unable to do so are asked to complete and return the Form of Proxy.

OUR EMPLOYEES AND CONSULTANTS

Mark Adams	Darilyn Fortuna	Doug Kidd	Brenda Parker
Pabla Andaur	Jim Fry	Les Kingdon	Dianne Poncelet
Rusty Anderson	Trevor Fulton	Todd Klippenstein	Paul Prociuk
Rob Aubertin	Angie Furdievich	Tom Kokotailo	Terry Prokopy
Ray Bahr	Marilyn Gardener	Marvin Kraelman	Lesley Rathgeber
Laura Bailes	Bruce Gawalko	Darcy Lamoureux	Bruce Richert
Kristine Beard	Don Geherman	Gary Laturmus	Terry Robichaud
Chad Beaulieu	Bruce Gibson	Shareen Lawrence	Greg Ross
Brad Benesch	Andy Gilbreath	Brian Ledrew	David Russell
Al Bessel	Ian Gillies	George Mahan	Luc Sabourin
Dennis Betts	Alan Glessing	Ian Martinot	Patricia Sardinha
Jason Bosma	Brad Granley	Kathy Matheson	Lawrence Schaff
Irvin Bouck	Mark Gray	Joe McAvoy	Irving Scott
Robert Bougie	Indy Grewal	Jim McBeth	Laura Silbernagel
Irene Britton	Trevor Hans	Mike McBeth	Malcolm Sills
Judy Britton	Dave Hendrickson	Debbie McBride	Darrell Spink
Debbie Carver	Kari Herman	Jim McIntosh	Brad Stack
S. Ken Chalmers	Jeannette Hibbert	Gord McLean	Terry Stasiuk
Sandy Cunningham	Paul House	Harold McLean	Dorsey Sunderland
Marcia Dee	Bill Hughes	Jana McLean	Eric Tjostheim
Bill DeGroot	Andrea Huitema	Dan Mears	Ken Veres
Dennis DeGroot			

ANNUAL GENERAL MEETING

Shiningbank Energy
Income Fund will hold its
Annual General Meeting
and Special Meeting of
unitholders on Wednesday
May 12, 2004 beginning
at 3:00 p.m. at the
Calgary Petroleum Club,
319 – 5th Avenue S.W.,
Calgary, Alberta.

Reply if you would like to receive **news releases, annuals and quarterlies:**

NAME _____

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CITY _____

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I would like information forwarded to me via:

☐ Fax ☐ Email ☐ Direct mail

☐ I would like information on the Distribution Reinvestment Plan

Corporate Information

HEAD OFFICE

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TRUSTEE

Computershare Trust Company of Canada
Calgary, Alberta

AUDITORS

KPMG LLP
Calgary, Alberta

ENGINEERING CONSULTANTS

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta

LEGAL COUNSEL

BOARD OF DIRECTORS

Arne R. Nielsen
Chairman

David M. Fitzpatrick
*President and
Chief Executive Officer*

D. Grant Gunderson
Director

Edward W. Best
Director

Warren D. Steckley
Director

OFFICERS

David M. Fitzpatrick
*President and
Chief Executive Officer*

Bruce K. Gibson
*Vice President,
Finance and
Chief Financial Officer*

NOTICE OF MEETING

The Special and Annual General Meeting of the unitholders of Shiningbank Energy Income Fund and the Annual General Meeting of Shiningbank Energy Ltd. will be held on Wednesday May 12, 2004 beginning at 3:00 p.m. (local time) at the Calgary Petroleum Club 319 – 5th Avenue S.W., Calgary, Alberta, Canada. Unitholders are encouraged to attend, and those unable to do so are asked to complete and return the Form of Proxy.

Shiningbank Energy Income Fund

Suite 1310, 111 – 5th Avenue S.W.
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SHININGBANK ENERGY INCOME FUND

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OUR EMPLOYEES AND CONSULTANTS

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Rob Aubertin	Angie Furdievich	Tom Kokotailo	Terry Prokopy
Ray Bahr	Marilyn Gardener	Marvin Kraelman	Lesley Rathgeber
Laura Bailes	Bruce Gawalko	Darcy Lamoureux	Bruce Richert
Kristine Beard	Don Geherman	Gary Laternus	Terry Robichaud
Chad Beaulieu	Bruce Gibson	Shareen Lawrence	Greg Ross
Brad Benesch	Andy Gilbreath	Brian Ledrew	David Russell
Al Bessel	Ian Gillies	George Mahan	Luc Sabourin
Dennis Betts	Alan Glessing	Ian Martinot	Patricia Sardinha
Jason Bosma	Brad Granley	Kathy Matheson	Lawrence Schaff
Irvin Bouck	Mark Gray	Joe McAvoy	Irving Scott
Robert Bougie	Indy Grewal	Jim McBeth	Laura Silbernagel
Irene Britton	Trevor Hans	Mike McBeth	Malcolm Sills
Judy Britton	Dave Hendrickson	Debbie McBride	Darrell Spink
Debbie Carver	Kari Herman	Jim McIntosh	Brad Stack
S. Ken Chalmers	Jeannette Hibbert	Gord McLean	Terry Stasiuk
Sandy Cunningham	Paul House	Harold McLean	Dorsey Sunderland
Marcia Dee	Bill Hughes	Jana McLean	Eric Tjostheim
Bill DeGroot	Andrea Huitema	Dan Mears	Ken Veres
Dennis DeGroot	Connie Hutchison	Rob Miller	Ed Wall
Andy Dezaeyer	Line Johnson	Dwayne Mindus	Aaron Watt
Shirley Dunn	Paul Johnston	Greg Moore	Dan Williams
Rob Dyck	Tara Kaupp	Ben Morris	Donna Wilson
Richard Eric	Jerry Keeler	Brenda Mychasiuk	Rose Wong
Doug Errico	Sonia Kelly	Brian Ontko	Cory Yee
Dave Fitzpatrick			

ABBREVIATIONS

bbl	barrels of oil or natural gas liquids
bcf	billion cubic feet of natural gas
boe	barrels of oil equivalent (6,000 cubic feet of natural gas is equivalent to one barrel of oil)
/d	per day
mbbl	thousand barrels
mboe	thousand barrels of oil equivalent
mmboe	million barrels of oil equivalent
mcf	thousand cubic feet of natural gas
mmcf	million cubic feet of natural gas
mmbtu	million British thermal units
NGL	natural gas liquids
tcf	trillion cubic feet of natural gas

A NOTE ABOUT BOES

The term boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

www.shiningbank.com



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